APPENDIX B-I
STANDARD OPERATING PROCEDURES FOR EXPLORATION, DEVELOPMENT, PRODUCTION, AND ABANDONMENT— OIL AND GAS

Once an oil and gas lease has been issued, the lessee or operator is granted the right to conduct certain operations on the leased lands (unless otherwise limited by special stipulations in the lease). The purpose of this appendix is to provide the reader with a general description and understanding of typical activities and current standard operating procedures that can be anticipated to occur for oil and gas exploration, development, production, and abandonment. The general information presented in this appendix is an integral part of the assumptions made in the analyses for this Resource Management Plan Amendment/Environmental Impact Statement (RMPA/EIS) (refer to Chapters 2 and 4 and Appendix A-III). It was assumed that the technology of oil and gas exploration and development will not change significantly during the life of this document; that is, to the extent that the RMPA/EIS decisions are affected.

Successful exploration and development generally progresses through five basic operational phases. These include (1) preliminary investigation (includes geophysical exploration), (2) exploratory drilling, (3) development, (4) production, and (5) abandonment. Several operational phases can occur in the same area at the same time. One company may drill an exploratory well on a lease while another company conducts preliminary investigations nearby. A lapse of several months or perhaps years may occur between the preliminary investigation and exploratory drilling phases. A lapse of several weeks, months, or years also may occur between the exploratory drilling and development phases. The development and production phases may occur simultaneously, especially if a large field has been discovered. On average, only a relatively small percent of the wildcat (exploratory) wells drilled in the United States are successful.

It may take several years to determine whether an exploratory well is a financial success. If it is a success, the operations progress through the three remaining phases over a time span that may range up to 50 years. The lapsed time between the production and abandonment phases of a field may be 15 to 20 or more years.

If geophysical exploration and/or exploratory drilling are unsuccessful in discovering a commercial deposit, operations are terminated and abandonment is initiated. The operation also may proceed directly from development to abandonment if one or more of the development wells is unsuccessful.

PRELIMINARY INVESTIGATIONS

A lease is not required to conduct preliminary investigations for Federal oil and gas; however, geophysical operations must be reviewed and a permit must be approved by the surface-management agency. Refer to Chapter 1 of the Surface Operating Standards for Oil and Gas Exploration and Development "Gold Book"[1] for a description of the permitting processes required by the Bureau of Land Management (BLM). BLM Manual H-3150-1 also describes surface-management requirements.

Indications of the presence of oil and gas can be obtained by various prospecting methods including geologic, geochemical, and remote investigations (e.g., examination of rock outcrops, seeps, and topography) and geophysical investigations (e.g., gravity, geomagnetic, and seismic reflection surveys). Prospecting via geophysical investigations means does not guarantee a successful find, but the combination of geophysical information and geological understanding reduces the changes of drilling a dry hole (unsuccessful test). These prospecting methods are described below.

Geologic and Remote Investigations

Geologic investigation begins with a review of geologic and technical data available for the area of interest. If this preliminary data indicate a potential for oil and gas, information for specific areas or trends are evaluated. If the area does not have a history of producing, no previous wells have been drilled, and the preliminary data suggest conditions are favorable for oil and gas, an extensive geophysical exploration program covering a large area may be undertaken to collect the subsurface data in order to evaluate the oil and gas producing potential.

Remote investigations may be conducted either from the air or on the ground. These are preliminary investigations that involve only casual use (i.e., minimal surface or subsurface disturbance) and no permits are required. However, the investigators must comply with the rules and regulations of the appropriate surface-management agency. A Federal oil and gas lease does not grant an exclusive right to conduct remote investigations and geophysical exploration. These activities may be conducted prior to or after leasing by either the lessee or someone other than the lessee. These investigations may result in an expression of interest to lease specific areas.

[1]Third edition, prepared by the Bureau of Land Management and Forest Service Rocky Mountain Regional Coordinating Committee, January 1989.

Geological Surveys

Geological surveys normally are a casual use. Rock outcrops and topography are examined visually to determine the structural attitude and age of surface formation, and surface maps are prepared. In some areas, sufficient information may be obtained to enable the geologist to recommend a drilling location without conducting additional exploration work.

Geochemical and Soil-gas Surveys

Geochemical and soil-gas surveys involve casual use of the land. In geochemical surveys, the chemical contents of water, soil, or vegetative samples are analyzed for the minute presence of oil or gas.

Geophysical Prospecting

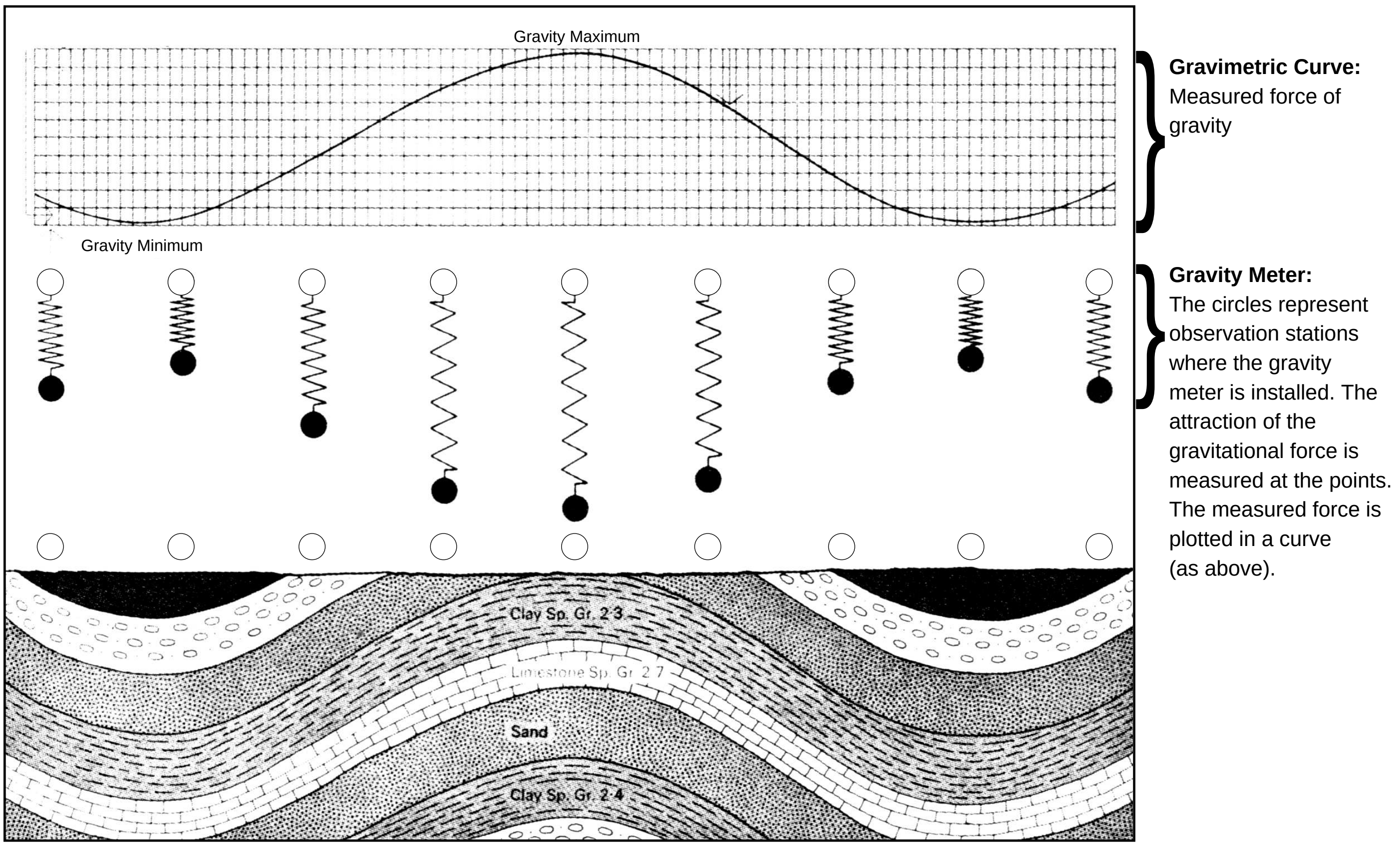
Geophysics deals with the composition and physical phenomena of the earth and its liquid and gaseous environments. The phenomena most commonly interpreted in oil and gas exploration are earth magnetism, gravity, and especially seismic vibrations. Sensitive instruments are used to measure variations in a physical quality that may be related to subsurface conditions. The interpretations of these conditions, in turn, indicate probable oil- or gas-bearing formations.

Gravity Surveys

Gravitational prospecting detects micro-variations in gravitational attraction caused by the differences in the density of various types of rock. Data derived from gravity surveys are used to generate anomaly maps from which faults and general structural trends can be interpreted (Figure B-1). Gravity surveys generally are not considered definitive due to the many data corrections required (e.g., terrain, elevation, latitude, etc.) and the poor resolution of complex subsurface structures. Therefore, gravity surveys may be used in conjunction with other methods.

The instrument used for gravity surveys is a small portable device called a gravimeter, which can be carried by an individual. Generally, measurements are taken at many points along a linear transect looped back to a reference point that is repeated by sample. The gravimeter is transported either by backpack, helicopter, or off-road vehicle (ORV).

There is little surface disturbance associated with gravity prospecting except that which may be caused by ORV use to transport equipment.



Gravity Meter Survey Principles

Figure B-1

Geomagnetic Surveys

Magnetic prospecting is used to a limited extent in oil and gas exploration. Magnetic surveyors use an instrument called a magnetometer to detect small magnetic anomalies in the earth's crust. Magnetic surveys can detect large trends or lineaments in basement rocks and the approximate depth to those basement rocks, but in general magnetic surveys provide little specific data to aid in petroleum exploration. Again, many data corrections are required to obtain reliable information and maps generated from magnetic data lack resolution and are considered preliminary. Magnetometers vary greatly in size and complexity and in general most magnetic surveys are conducted from the air by suspending a magnetometer under an airplane. Magnetic surveys conducted on the ground are nearly identical to gravity surveys and there is little or no surface disturbance.

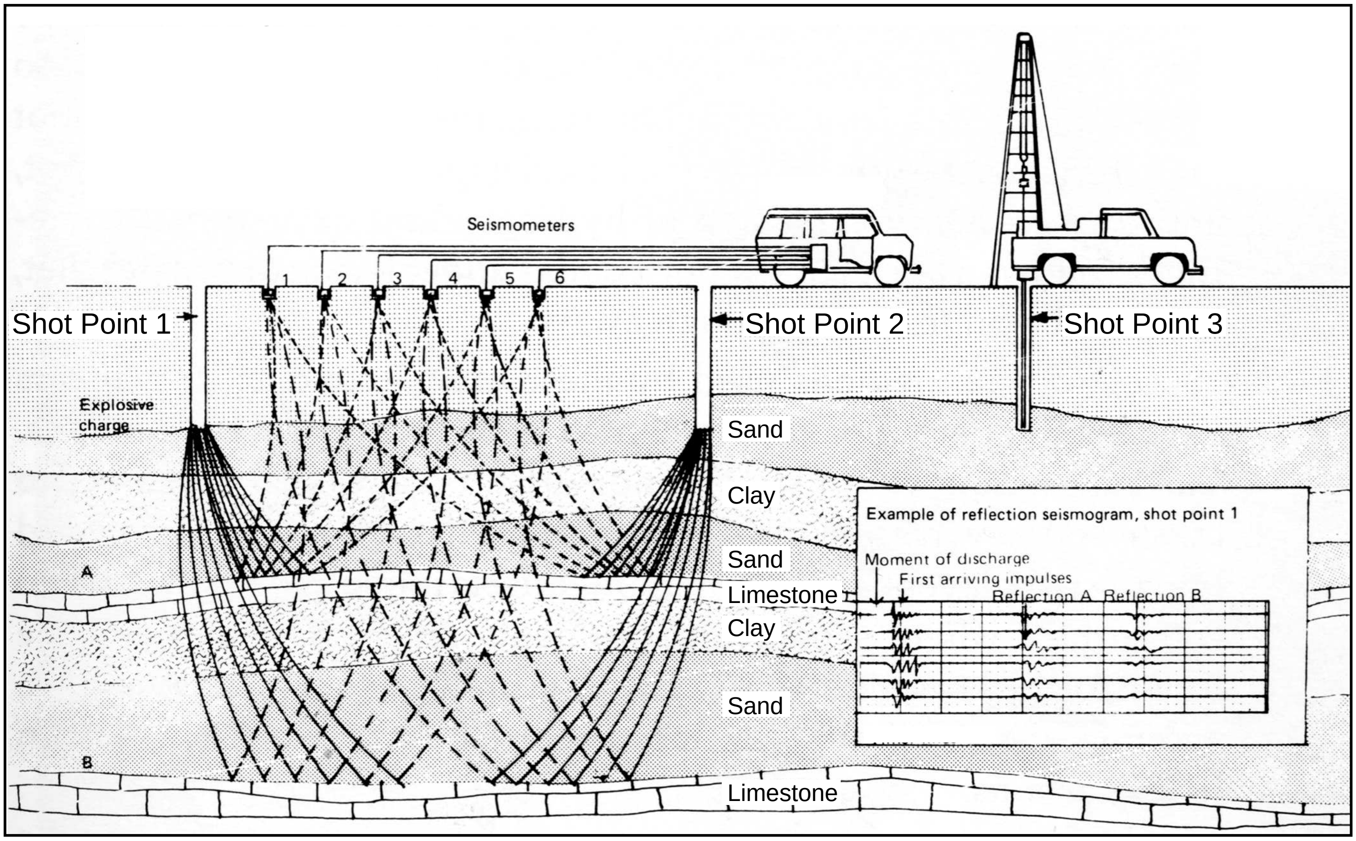
Seismic Reflection Surveys

Seismic prospecting is the most common indirect method used for locating subsurface structures that may contain oil and/or gases. Shock waves are induced into the earth using one of several methods. Vibroseis and drilling/explosives are the two most commonly used methods for producing the shock wave. These waves travel downward and outward encountering and reflecting off of various strata, each having a different seismic velocity. Sensing devices called geophones are placed on the surface to detect these reflections. The geophones are connected to a data recorder, which stores the data. The time required for the shock waves to travel from the seismic energy source down to a given reflector (a change in rock strata) and back to the geophone can be correlated to the depth of the reflector (Figure B-2). The data collected are then processed by computer to create a velocity/amplitude image of the subsurface geology in time.

Seismic surveys can be conducted two-dimensionally (2-D) (line with vertical depth) or three-dimensionally (3-D). The 2-D seismic programs are carried out with the shots (source of energy or vibration) and receivers (from sensing devices) on or offset slightly from the same line. In 3-D seismic programs, the shots and receivers are arranged in an areal pattern on the ground surface that may vary considerably in dimension. The advantages of 3-D surveys are the processing possibilities, reduction in the assumptions made during 2-D processing, and alignment and design of the survey to the prospect.

Vibroseis Surveys

The thumper and vibrator methods pound or vibrate the earth to create the shock wave. Usually three to five large trucks, each equipped with vibrator pads (about 4 feet [1.2 meters] square), are used. The pads vibrate the ground surface along a series of linear routes that are defined for each project's survey area. In 3-D surveys, long cables that contain sensors are placed perpendicular to the source lines in order to detect the reflected vibrations. The pads are lowered to the ground and vibrators



Explosive charge at shot point 1 creates shock waves that are reflected by subsurface formations to seismometers and are recorded by equipment in truck.

Principles of Seismic Reflection Survey

Figure B-2

on all trucks are turned on simultaneously. Information is recorded, the trucks are moved forward a short distance, and the process is repeated. Truck traffic is generated by the trucks along source lines, trucks needed to lay the sensor cables and receiver lines that report the detections to a central monitoring area, and by trucks needed to conduct repairs on receiver lines. Surface disturbance occurs along access routes if off-road travel is required, although little surface area is required to operate the equipment at each test site. All-terrain vehicles (ATVs) may be used in place of trucks to reduce impacts on test sites. The 3-D surveys often involve greater surface disturbance due to the grid layout that is used in place of the linear 2-D method.

Drilling/Explosives

The drilling method uses truck-mounted drills that drill small-diameter holes to depths of 30 to 200 feet (9 to 61 meters). Four to 12 holes are drilled per mile of line. Usually, a charge of explosives is placed in the hole, covered, and detonated. The amount of dynamite needed for a reflection shot varies from less than 1 pound to several hundred pounds, depending on the nature of the material in which the shot is fired. The explosion sends energy waves that are reflected back to the surface from subsurface rock layers. The holes are drilled along a line that can be miles in length. In rugged topography, inaccessible to wheeled vehicles, a portable drill may be transported by helicopter.

Under normal conditions, 3 to 5 miles of line can be surveyed each day using the explosive method. The vehicles used for a drilling program include several heavy truck-mounted drill rigs, water trucks, a computer recording truck, and several light pickups for the surveyors, shot-hole crew, geophone crew, permit person, and party chief. Public roads and existing private roads and trails are used to the extent possible. Off-road, cross-country travel also is necessary. Motor graders and/or dozers may be required to provide access to remote areas. Several trips a day are made along a seismograph line, which usually establishes a well-defined two-track trail. Drilling water, when needed, is usually obtained locally.

Primacord

Another seismic technique involves the use of explosive cord. The cord is buried in a 2.5-foot (0.75-meter)-deep furrow that is plowed by a specially designed mechanical plow mounted on a tractor. Multiple sets of cord, often in a pattern, are buried at the same time. This method offers efficiency advantages over the shot-hole seismic method in that it is faster, less costly, and the quality of the data is often improved. However, surface disturbance may be considerably greater than with the shot-hole seismic method.

Post-Lease Preliminary Investigations

If interpretation of preliminary investigations indicate that an oil or gas trap may exist in an area, the company may secure leases either directly through the Federal leasing system or from existing leaseholders through assignment (lease is purchased and ownership is assigned). Additional preliminary investigations may be carried out after a lease is acquired. Post-leasing investigations may include airborne and surface operations similar to those of the preleasing phase. The lessee may intensify the seismic studies by laying out a criss-cross pattern of lines tying to the previous seismic lines, or conduct 3-D seismic surveys. Other preliminary investigations also may be initiated prior to drilling.

EXPLORATORY DRILLING

Where preliminary interpretations are favorable and data warrant further exploration, exploratory drilling is conducted. More precise data on the geologic structure may be obtained by stratigraphic tests. The presence of suspected oil and gas deposits may be confirmed by exploratory (wildcat) drilling of deep holes.

Permitting Process

Exploratory drilling is authorized only by a Federal oil and gas lease, but cannot be conducted unless an Application for Permit to Drill (APD) is approved containing an adequate Surface Use Plan of Operations (SUPO) and drilling plans.

Proposed construction of the well location and access roads, and other facilities and operations that involve surface disturbance conducted under the terms of a lease must be approved by the appropriate surface-management agency before such activities are conducted. Regardless of which surface-management agency, the proposed development of a Federal lease (i.e., Federal minerals) must be approved by BLM. Operations must be approved and conducted in accordance with (1) lease terms; (2) 43 CFR 3160; (3) 36 CFR 228, Subpart E; (4) Onshore Oil and Gas Order No. 1, and other onshore oil and gas orders; (5) applicable Notices to Lessees (NTLs); (6) any conditions of approval; and (7) any subsequent orders of the authorized officers of the BLM.

No drilling operations or related surface disturbance can be conducted without an approved APD. There are two options available to the oil and gas operator when applying for approval of an APD. After the company makes the decision to drill a well, they submit a Notice of Staking (NOS) prior to submitting an APD, or it may submit only an APD.

Notice of Staking

The NOS consists of an outline of what the company intends to do including a location map and sketched site plan and lease description. The NOS document is reviewed by BLM to identify any conflicts with known resource values. Also, it is used during the on-site inspection and to provide the preliminary data to assess what items are needed to complete an acceptable surface use plan and drilling program.

Application for Permit to Drill

An operator or lessee must submit a completed APD to the BLM whether or not the NOS is used. An APD includes a drilling plan, which consists of a surface use program and a drilling program. The detailed information required to be submitted under each program is identified in Onshore Oil and Gas Order No. 1 and 36 CFR 228, Subpart E. An onsite inspection of the proposed well site, road location, and other areas of proposed surface use is conducted prior to approval. The inspection team may include, but not be limited to, BLM representatives, the lessee or operator, operator's principal drilling and construction contractors, and other relevant parties. The purpose of the on-site inspection is to identify issues and potential environmental impacts associated with the proposal and the methods for mitigating those impacts. These may include making adjustments to the proposed well site and road locations, identifying the construction methods to be employed, and identifying reclamation standards for the lands after drilling. Environmental documentation must be completed to satisfy the National Environmental Policy Act. The surface-management agency may choose to provide mitigation measures. The BLM is responsible for approval of the drilling program, protection of groundwater resources, and final approval of the APD.

When final approval is given by BLM and 30 days has transpired, the operator may commence construction and drilling operations. Approval of an APD is valid for one year. If construction does not begin within one year, the stipulations must be reviewed prior to providing an extension or approving another APD.

Other proposals to occupy the surface that involve surface disturbance, but are not associated with drilling a well, also must receive advance approval under the procedures described above.

<u>Stratigraphic Tests</u>

Stratigraphic test holes may be drilled 100 to 500 feet (30 to 152 meters) deep to locate geologic indicators as part of the lease venture. The holes are usually drilled with truck-mounted equipment and disturb a relatively small area. Casing is needed for stratigraphic holes in areas of shallow high-pressure zones. The roads and trails constructed for access to the test sites are temporary and involve minimal construction. Only one to three days are required to drill each hole. The drill site occupies an area approximately 30 feet by 30 feet (9 meters by 9 meters) and is sometimes placed in the center of a new or existing trail.

Wildcat Wells

Wildcat wells are deeper tests, require larger drilling rigs with support facilities, and may disturb a larger surface area than stratigraphic tests. Construction of access roads, drill pads, reserve pits, and, in some cases, worker camps and helipads, are required to conduct exploratory drilling operations.

The well site is selected on the basis of prior surface investigations, seismic surveys, data from other wells that have been drilled in the area. Other considerations may include topography, accessibility, requirements of lease stipulations, and protection of surface resources.

Usually, attempts are made to locate wells sites on the most level location available that accommodates the intended use consistent with reaching the geologic target. The drill site layout also can be oriented to conform to or fit into the topographic conditions at the drill site. However, safety considerations in a hydrogen sulfide (H_2S) area may be an overruling factor when determining the topographic setting and providing adequate escape routes for the drill crew. In general, steeply sloping locations, which require deep, nearly vertical cuts and steep fill slopes, are avoided or appropriately mitigated. The well site also is reviewed to determine its effect in conjunction with the location of the access road.

Surface Requirements and Construction

Upon approval of the APD, construction may begin within the leasehold. If facilities (e.g., tank batteries, pipelines, truck depots, power lines, and access roads) that occupy Federal land outside the lease or unit boundary, a right-of-way also is required. The right-of-way is issued by the surface-management agency.

A general description of surface requirements and construction of roads and well sites follows.

Roads

Moving equipment to the construction site requires moving several semitruck loads (some overweight and over-width) over public and private roads. Generally, existing roads and trails are used to the extent practical and improved where needed to accommodate the construction traffic. This may include installation of culverts and cattle guards, if needed. The lengths of access roads vary. Generally, the shortest feasible route consistent with the topography is selected to reduce the haul distance and construction costs. In some cases, potential environmental impacts or existing transportation plans dictate a longer route. On public land in New Mexico, roads are constructed in accordance with the policy of the New Mexico State Office of BLM.

Road width may vary depending on the use of the road; however, access roads to a well site are usually constructed to a 12- to 16-foot (3.6- to 4.8-meter)-wide travel surface (in relatively level terrain).

Road surfacing may be required because of adverse soil conditions, steepness of grade, and moisture conditions. The total acreage disturbed for each mile of access road construction varies significantly with steepness of slope. In rough terrain the type of construction is sidecasting, where the material taken from the cut portion of the road is used to construct the fill portion.

If a well is plugged, roads may require reclamation. If a well is productive, roads may have to be upgraded and maintained.

Well Sites

Well site selection and construction incorporates considerations of the amount of level surface required for safe assembly and operation of a drilling rig. The amount of level surface area safely assembling and operating a drill rig varies with the type of rig, but averages 400 feet by 400 feet (122 meters by 122 meters); however, not all of the drill site may be used. In some cases, a larger area may be required; for example, the drill sites in the Bennett Ranch Unit are 400 feet by 600 feet (122 meters by 183 meters) for safety reasons in this area.

Well sites located on flat terrain usually require little more than removing the topsoil (all soil material suitable for plant growth) and vegetation from the site and then a base (e.g., of caliche) is built for the stability of the drilling rig.

Well sites on ridge tops and hillsides are constructed by cutting and filling portions of the location to provide a level area (drill pad) to accommodate the drill rig, ancillary facilities, and drilling operations. Normally, at least 25 feet (7.6 meters) (between the drill point and outer edge of the drill pad) is required to be on an area of cut instead of fill. The substructure of the drilling derrick must be located on solid ground as settling of uncompacted fill material under the drill rig may cause the substructure and derrick to lean and even fall. The majority of excess cut material may need to be stockpiled in an area that will allow easy recovery for reclamation.

In addition to the drill pad, a reserve pit is constructed to accommodate spent drilling fluids and cuttings resulting from drilling, and to provide a large quantity of mud to control pressure variations during drilling. The pit is usually square or oblong, but may be constructed in another shape to accommodate topography. The reserve pit is a depth determined sufficient to accommodate the particular situation, but normally is not deeper than 8 feet (2.4 meters). The pit must be deep enough to completely cover cuttings, dried drilling fluids, and produced fluids to a depth of 3 or more feet (0.92 or more meters). This decreases plant mortality and improves reclamation success.

Depending on the relation of the drill site to natural drainages, it may be necessary to construct waterbars or diversions. The size of the area disturbed for construction and the potential for successful revegetation often depends on the steepness of the slope.

The drilling rig and its attendant facilities such as pumps, mud tanks, generators, pipe racks, tool house, etc., are located on the drill pad. Other facilities such as storage tanks for water and fuel may be located on or near the drill pad. Depending on the remoteness of the location, house trailers also are provided to house workers during drilling operations.

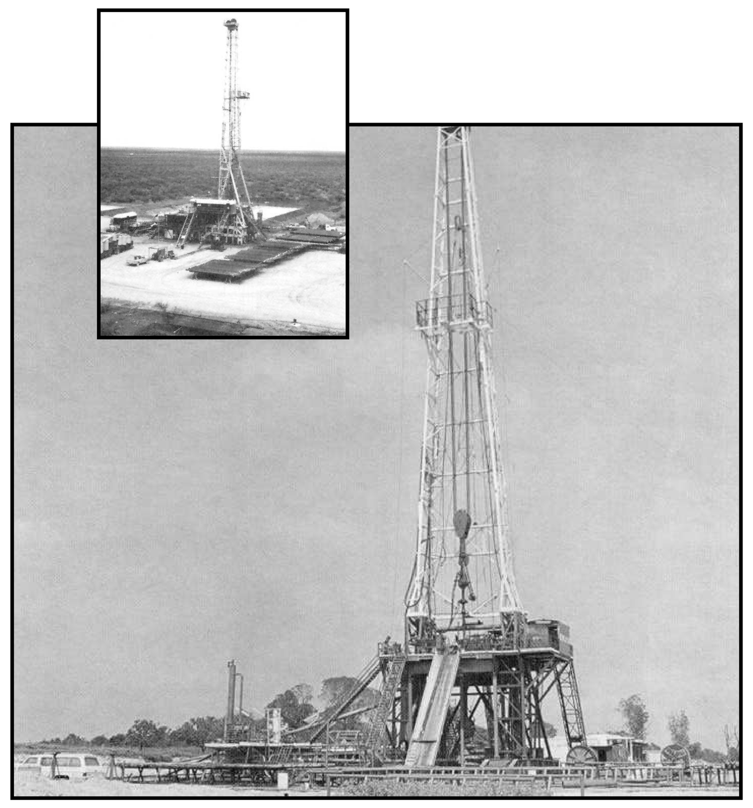
Drilling Operations

After well site and access road construction is completed, the drilling rig and associated equipment are moved to the site and erected. Moving a drilling rig requires 30 to 40 truckloads of equipment over public highways and private roads.

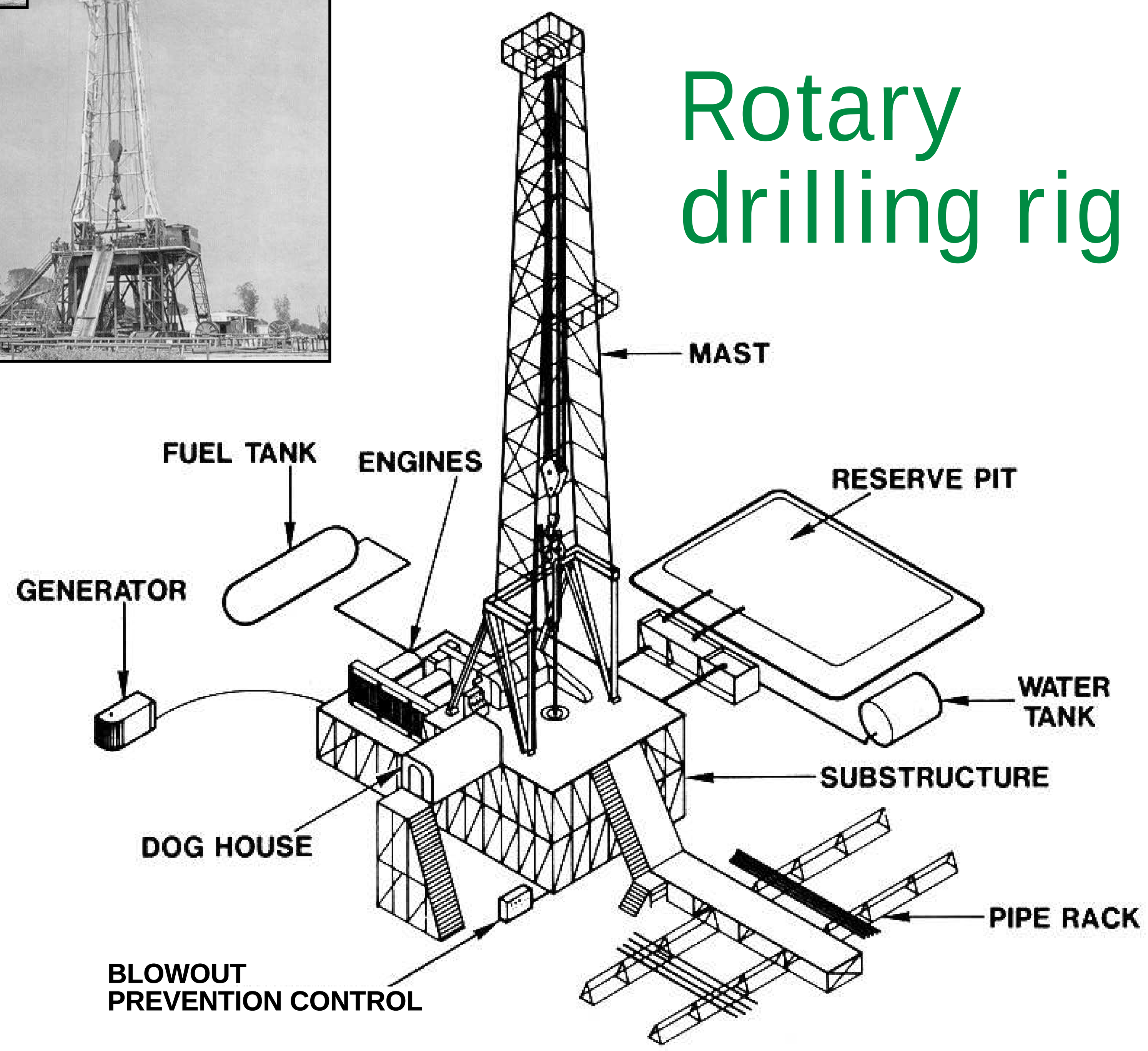
The most commonly used well drilling equipment is the rotary rig, which consists of (1) the rotary system, which consists of the drill bit attached to a length of tubular high tensile steel “drill-stem pipe” (collectively called the “drill string”) which is turned by a rotary table; (2) the mud-circulating system consisting of mud tanks, mud pumps, and reserve pit; (3) a hoisting system, which consists of a derrick (“mast”), crown block, and traveling block used to lift and lower the drill; (4) a power system, normally diesel-engine-powered electric generators; and (5) blowout prevention system that prevents high-pressure fluids in deep wells from escaping to the surface (Figure B-3). Other equipment includes tanks for drilling fluids and fuels.

Depending on the height of the substructures, the derrick may rise to more than 160 feet (48 meters) above the ground surface and is the most visible and noticeable feature of a drill rig. The commencement of drilling operations is commonly referred to as “spudding” the well. The actual drilling is accomplished by passing the drill string through the rotary table, which turns the drill string and bit, which in turn performs the actual drilling. The weight of the drill string provides downward pressure on the drill bit, which chips and pulverizes the rock as it rotates in the bottom of the hole. By continually adding more drill-stem pipe to the drill string, the hole is steadily deepened.

The initial hole is drilled to a depth of 80 to 100 or more feet (24 to 30 or more meters), depending on the surface geology of the area. The hole then is lined with conductor pipe. The space between the casing and the drilled hole (borehole) is filled with cement. This prevents unconsolidated surface formations from sloughing into the hole. The pipe must be set in rock that is capable of withstanding the maximum anticipated pressure to which it may be exposed.



Rotary drilling rig



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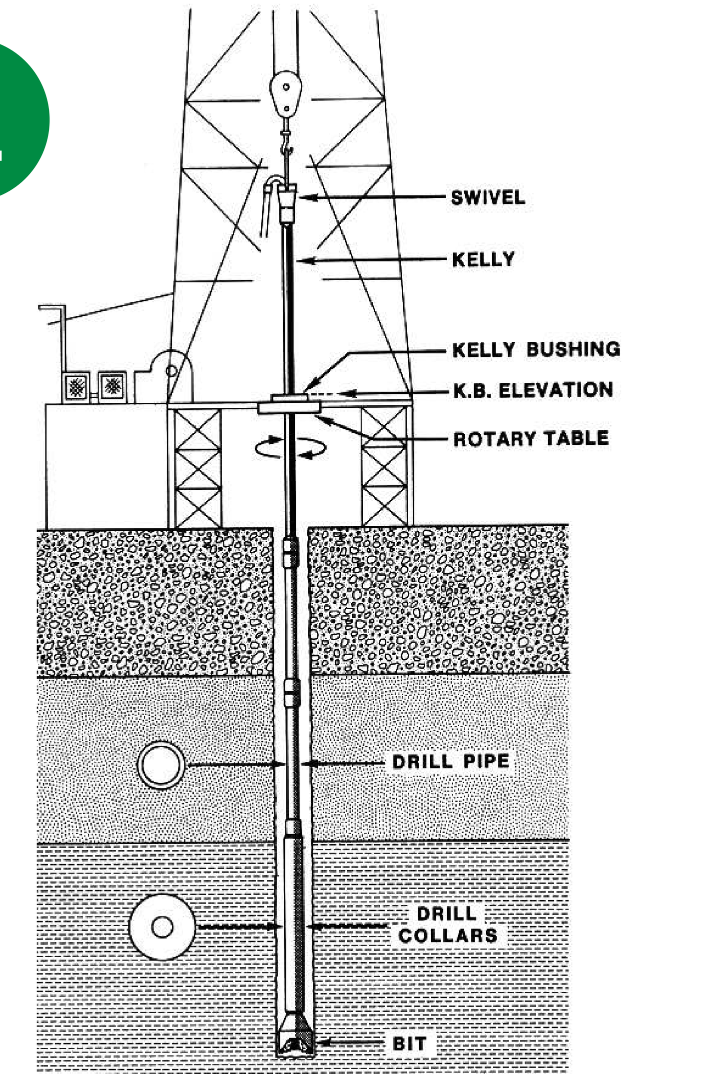
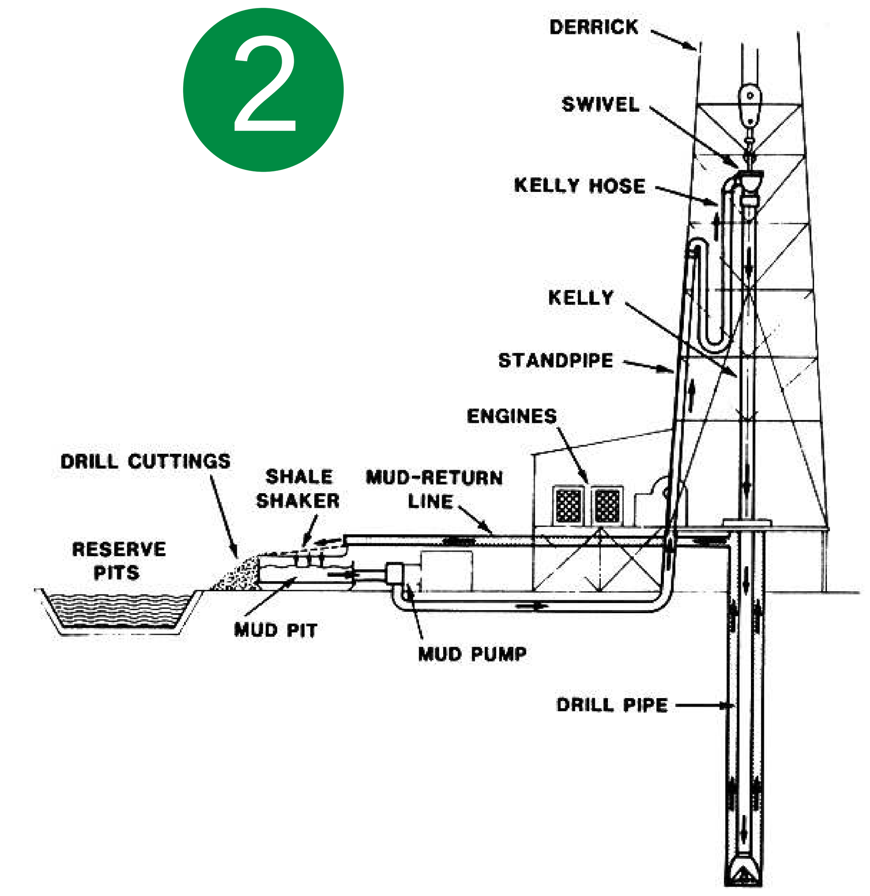


The rotary drill string and bit physically creates the hole by applying cutting action against the rock at the bottom of the hole.

2



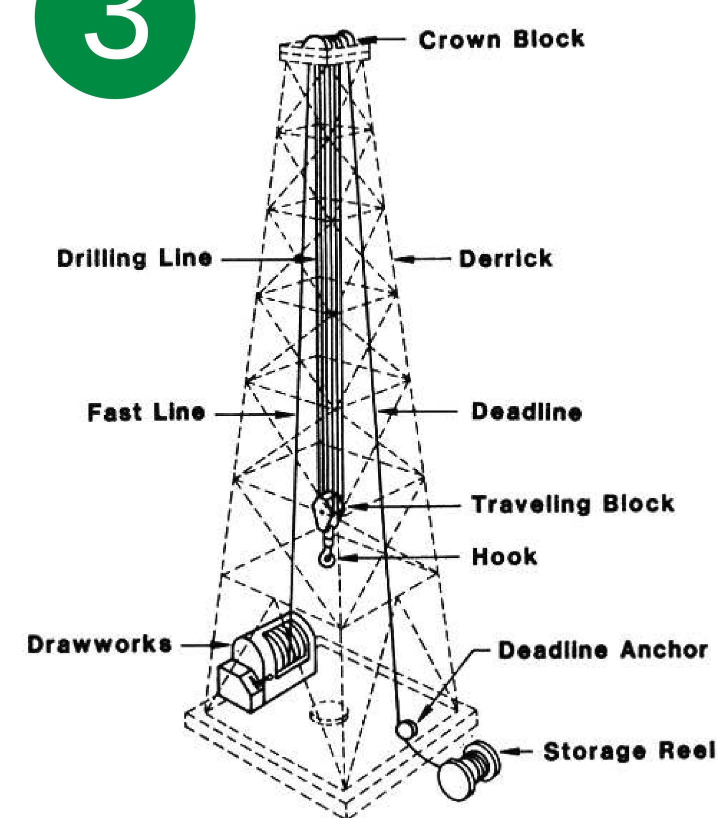
Fluid is continuously circulated down the inside of the drill pipe, through the bottom of the bit, and back up the annular space between the drill pipe and hole to:

- *carry broken rock fragments to the surface*
- *help counterbalance any high pressures encountered*
- *contribute to wellbore stability*
- *lubricate and cool the bit*

Five major systems essential to the operation of a rotary rig:

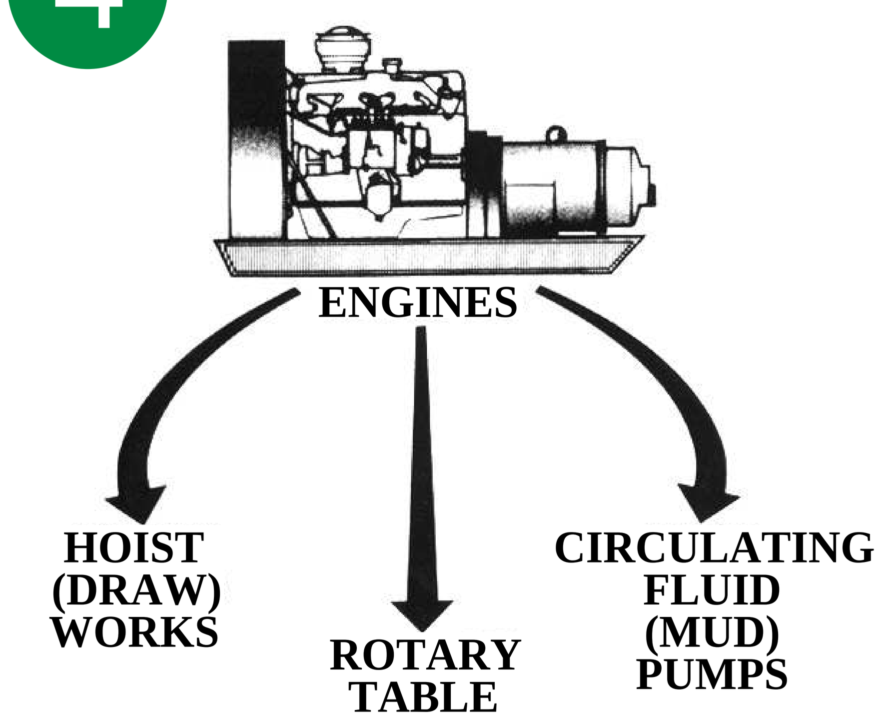
1. Drill string and bit system
2. Fluid circulating system
3. Hoisting system
4. Power system
5. Blowout prevention system

3



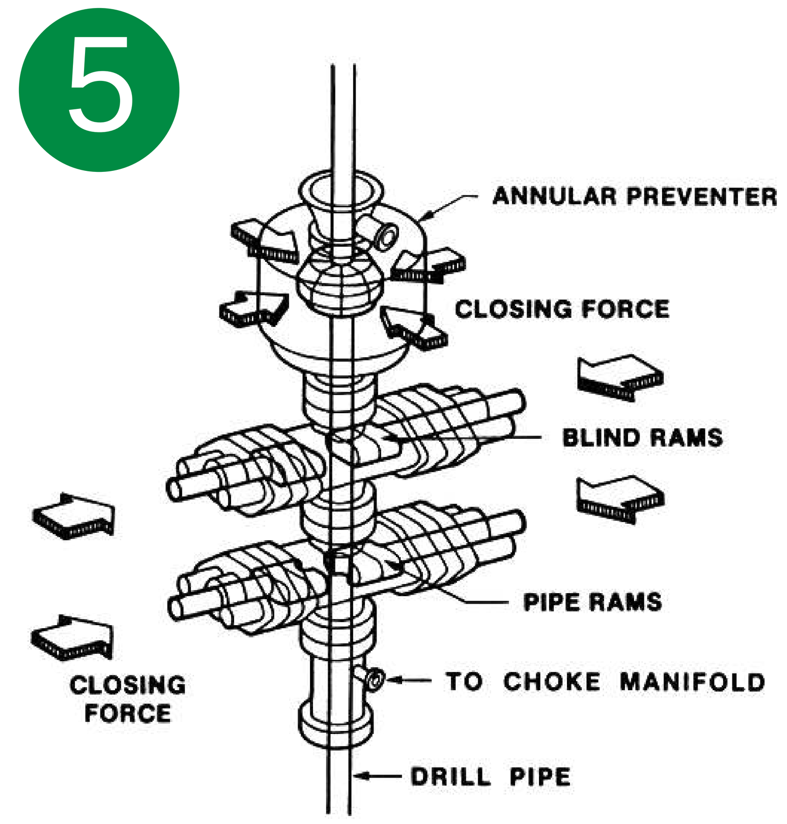
The rig's hoisting system lifts the drill pipe, drill collars, and drill bit in and out of the hole.

4



The power system commonly operates the hoist works, rotary table, and fluid circulating system. The engines generally use diesel fuel, and usually a large rig has more than 2,000 horsepower available for operating the equipment.

5



The blowout prevention system is equipment that prevents high pressure fluids in deep wells from escaping to the surface.

Typical Rotary Drilling

Figure B-3

After the surface casing is in place, a series of blowout preventer (BOP) valves are attached to the well. The valves close down the well in the event the drill bit penetrates rock formations exhibiting extreme pressure zones that could cause unexpected changes in pressure and a well blowout. Special attention is given to the prevention of well blowouts, and most of the equipment used to support the actual drilling operations is for controlling excess pressure that may be encountered in the formations drilled.

Blowout prevention equipment is tested and inspected, which may be witnessed by the rig personnel and BLM. The drill rig crew must be trained in safety and blowout prevention.

Drilling is resumed after installation of casing and the BOP using a smaller bit. After the borehole has penetrated all of the surface formations, which may contain fresh water, the bit and drill string are hoisted out of the well and another length of pipe (surface casing) is lowered into the borehole and cemented in place. The surface casing protects the useable quality water strata (aquifers) from being contaminated by the drilling mud.

Drilling mud (fluid) is circulated through the drill pipe and bit to the bottom of the hole, then up the bore of the well to the surface, possibly across a shell shaker screen that separates the cuttings from the fluid for analysis, while fluid flows. The mud, maintained at a specific weight and thickness, is used to cool the drill bit, lubricate the drill string, seal porous rock zones, prevent blowout or loss of drilling fluid, and transport the cuttings resulting from the drilling to the surface for disposal. Various additives are used to maintain the drill mud at the desired viscosities and weights. Some additives that may be used are caustic, toxic, or acidic. The spent drilling mud and rock chips are disposed in the reserve pit.

Water for drilling is hauled by truck to the rig storage tanks or transported by surface pipeline. Water sources are usually rivers, existing water supply wells, or reservoirs. Occasionally, water supply wells are drilled on or close to the drill site. The operator must obtain a permit from the State for the use of surface water or groundwater from a declared basin for drilling. Water continually is being transported to the well site during drilling operations. Although it will vary significantly from well to well, approximately 10,000 barrels (42-gallon barrels) or an average of 1.25 barrels (52.5 gallons) per foot of water may be required to drill an oil or gas well to the depth of 9,000 feet. If water is hauled by truck, a significant amount of traffic to and from the drill site will be generated by water hauling. More water is required if the underground rocks are fractured and drilling fluids are lost into the formation (lost circulation zone). Uncontrollable loss of drilling fluids may cause drilling to be terminated.

In some areas where drilling must penetrate clay or shale layers, oil-based drilling muds may be used instead of water-based muds after the surface casing has been installed and cemented. The oil-based muds prevent the clays or shales from swelling and caving into the borehole, which can result in the collapse of the borehole making it impossible to pull the bit out of the hole.

An alternate method of drilling, but used only in special cases, is circulating with air instead of mud. To drill with air, large compressors and related equipment are moved onto the site. In drilling, the air is not circulated and used repeatedly; rather, it makes one trip from the compressors, down the drill stem, out the bit, and up the annulus back to the surface, and is blown out a "blooey" line, or vent pipe. Usually, only part of a hole is drilled with air, then the rig is changed over to drilling mud. Among the problems associated with drilling with air, a major limitation is the chance of encountering water.

As the drilling proceeds, additional casings of concentrically smaller diameter are lowered into the well and cemented in place until the final depth (target zone) is reached. During the drilling process, the drill string must be pulled from the well periodically to change the drill bit, replace drill pipe joints, take a drill-stem test (DST), remove core samples, run electrical logs in the wellbore, and install casing in the wellbore. Core samples are analyzed to determine the type of rocks penetrated and their porosity, permeability, chemical properties, and hydrocarbon content.

Drilling operations continue 24 hours a day and 7 days a week. The crews usually work three 8-hour shifts or two 12-hour shifts a day. The greatest amount of human, vehicular, and equipment activity and accompanying noise, etc., occurs during construction and drilling activities. Traffic is generated by trucks hauling equipment and water, service companies delivering supplies and equipment and performing specialized work on the drill rig, drilling crew shift changes, well treatment, and testing equipment, etc.

Upon completion of the drilling, the well is "logged" with down-hole petrophysical instruments and tested to obtain information about the rock formation and production of fluids.

At the completion of drilling, the well is evaluated to determine if hydrocarbons can be commercially produced. Although a DST may have been conducted in a prior zone, a DST may be conducted at this time to measure directly the fluid content (water, oil, or gas) of formation and the amount of flow, as well as any shut-in pressure of the well. The well is logged by measuring the electric resistivity that provides information as to the porosity of the rock, the kind of fluids present, and fluid saturation level of the rocks. These physical characteristics of the rock formations and associated fluids are measured and recorded. If it is determined, based on the tests, that the well can be developed economically for production, the well is readied for production and connected to a gathering system (see Field Development and Production).

Directional Drilling

Although limited in use, directional drilling may be used where the drill site cannot be placed directly over the reservoir, as might be the case where a river or mountain is involved, where no surface occupancy is permitted on the leasehold, or where land use restrictions require centrally located drill sites.

There are limits both to (1) the degree that the wellbore can be deviated from the vertical and (2) the horizontal distance the well can be drilled from the well site to the target zone. The limit of horizontal distance also is affected by depth of the target zone, characteristics of the rock formation to be penetrated, and the additional costs of directional drilling. These factors all are considered before applying this technology.

If oil or gas is not discovered in commercial quantities, the well is considered dry. The operator must comply with BLM procedures for plugging and abandoning a dry hole and reclaiming the well site and possibly associated access roads.

FIELD DEVELOPMENT

The completion of a wildcat well as a commercial producer marks the potential beginning of the development of an oil and/or gas field.

Field Development Plans

A field development plan consists of a coordinated collection of site-specific drilling and surface use plans for individual wells with associated roads and flowlines. The lessee/operator may submit the plan when sufficient information is available to project a reasonably foreseeable development of the field. Sufficient information may not be available until one or more confirmation wells have been drilled to delineate the characteristics of the reservoir. The limits of a field located on a structural trap can be determined more easily than a stratigraphic field based on the information obtained from drilled wells and geophysical data. The proposed field development is subject to environmental analysis prior to approval or rejection of the APD.

The surface plan includes information on existing roads, the proposed location of the access roads, the proposed well or wells, flowlines, tank battery, and any camps, if required; the proposed location and type of water supply; the proposed waste disposal methods; plans for reclamation of the surface; and other information deemed necessary.

The subsurface information required to be submitted includes (1) occurrence and anticipated depths of fresh water aquifers, (2) expected depths of possible oil or gas productive zones above or below the zone already discovered, (3) other mineral-bearing formations, (4) the potential for entering highly permeable formations in which the drilling mud might be lost, (5) the anticipated pressures in the formations to be drilled, and (6) the potential for encountering other geologic conditions that could cause drilling problems. This information is obtained to determine whether the proposed drilling program is adequate, and to ensure the drilling mud, pressure control, casing, cementing, testing, well logging, and completion programs adequately protect the surface and subsurface environments, protect other subsurface resources, and provide safe working conditions.

Well-Spacing Pattern

Before development of an oil and gas field begins, a well-spacing pattern is established to allot a spacing unit for each well that will be drilled in the discovery area. The spacing pattern for drilling wells is set by the government. Oil well spacing patterns in the United States range from 2.5 acres per well to 640 acres per well. Spacing units established for oil production are usually closer than gas well spacings and are generally in multiples of 40 acres (40, 80, 160, 320, 640 acres per well). Gas well-spacing patterns in the United States range from 40 to 1,440 acres per well. Most spacing patterns established at the present time for production of gas are 160, 320, or 640 acres per well.

The well-spacing pattern established for an oil and gas field is the primary factor that determines the amount and intensity of human presence and associated activity during the development and operation of the field. Also, it affects the amount of surface disturbance and land area required to accommodate surface facilities. For example, if the well-spacing pattern is larger, the intensity and concentration of human activity will be lower and less overall surface disturbance will occur.

Unitization

In areas involving Federal lands, a unit consolidation of leases may be formed pursuant to 43 CFR Subpart 3180 through Subpart 3186. The boundaries of the area enclosed within a unit are determined by available geologic data.

A unit agreement provides for (1) development and operation of the field as a single, consolidated unit without regard to separate lease ownership; (2) the allocation of costs and benefits according to terms of the agreement; and (3) a single unit operator. Exploratory units also are formed to share the cost of (1) geologic and geophysical evaluation and (2) drilling exploratory wells to test geologic structures. Unit agreements involving Federal leases require BLM approval.

Leases that are committed to a producing unit are considered producing leases and will not terminate as long as production continues within the unit. As the limits of the productive area are defined by additional drilling, some leases may be dropped from the unit, others may join. If a Federal lease is dropped from a unit, the term of the lease may be extended for a period of two years if less than two years remain in the primary term of the lease.

Field development under an undivided unit agreement reduces the surface use requirements because all wells within the unit boundaries are operated as though they are located on a single lease. Development and operations of the field are planned and conducted by a single unit operator and, therefore, duplication of field processing equipment and facilities is minimized.

Drilling Procedures

The drilling of development wells is basically the same as the drilling of a wildcat well. Roads and other facilities are planned and constructed for long-term use.

Surface Use Requirements

Surface uses associated with oil and gas field development wells include access roads, well sites, flowlines, compressor facilities, storage tank batteries, and facilities to separate oil, gas, and water. In remote locations, worker camps may be required. Access roads are planned, located, and constructed for long-term use as opposed to roads built for short-term use to drill wildcat wells.

Surface Use and Construction Standards

The minimum standards for design, construction, and oil and gas operations are set forth in the Surface Operating Standards for Oil and Gas Exploration and Development "Gold Book." The Gold Book prescribes the minimum operating standards for oil and gas operations on Federal lands. The objective of the standards is to minimize surface disturbance and effects on other resources, and retain the reclamation potential of the disturbed area. In addition, the Las Cruces Field Office of BLM developed best management practices to be implemented as part of fluid minerals projects on public land within the Planning Area (see Appendix A-III). Also, site-specific construction and design standards and mitigation measures may be required depending on the proposed activities and conditions encountered at the construction site.

The locations for well sites, tank batteries, reserve pits, pumping stations, roads, and pipelines are selected to minimize, to the extent practical, the long-term impacts on other resources and disruption of other land uses. Ideal locations for oil and gas activities are seldom available and avoidance of damage to surface resources is not always possible. Well sites must be located to take advantage of the geologic target sought. Pipelines, because of their linear nature, cannot always be located to avoid all areas exhibiting environmental sensitivity to impacts. Avoidance of construction on steep topography and unstable soils; near streams and other open water areas; on cultural resource sites; and in threatened, endangered, or sensitive species habitats is attempted; however, it is not possible or practical to avoid all situations. Therefore, special construction techniques and operating practices may need to be employed to minimize the impacts.

Oil Field Production Development

Production operations in an oil field begin soon after the discovery well is completed. Portable and temporary facilities may be located on the drill pad are used to initiate the production of oil from the reservoir. As further drilling proceeds and reservoir limits are established, permanent production facilities are designed and installed at centralized locations. The type, size, and number of the facilities are determined by the number of producing wells, expected production rates, volumes of gas and water expected to be produced with the oil, the number of separate leases involved, and whether or not the field is being developed on a unitized or individual lease basis. Development of production on a lease basis requires handling and processing facilities be installed on or near each lease/well.

Gas Field Production Development

Production operations in a gas field begin when a pipeline to a market outlet is constructed. Market pipelines are not economical unless sufficient gas reserves have been proven to exist by drilling operations. Gas wells are often shut-in after completion for periods of several months or years until a pipeline connection becomes available and economical. As gas is transported by pipeline rather than truck, field development includes installation of gathering pipelines, compressor stations, and potential gas plants prior to the transfer to the market pipeline.

Rate of Development

The rate at which development wells are drilled in a newly discovered field depends upon (1) the probability of profitable production, (2) whether the field is developed on a lease basis or unitized basis, (3) the availability of drilling equipment, (4) protective drilling requirements, (5) the degree to which limits of the field are known, (6) operator business practices, (7) availability of investment money to fund development, and (8) market conditions (price of commodity).

A significant factor when determining how fast field development is undertaken is indicated production potential. If large productive capacity and substantial reserves are indicated, development drilling proceeds at a rapid pace. If there is a question as to whether indicated reserves are sufficient and economic to warrant additional wells, the development drilling occurs at a slower pace. An evaluation period to observe production performance may follow between the drilling of each well.

Development on an individual lease basis proceeds more rapidly than development in a unitized area. When development drilling is undertaken on a lease basis, each lessee drills his own well(s) to obtain production from the field. This creates a competitive situation where the first wells drilled potentially produce the greatest share of oil and/or gas from the reservoir and quickest and greatest return on investment. When unitized, all owners within the “participating area” share in a well’s production regardless of whose lease the well is located on. The development of a reservoir then can proceed in an orderly manner and pace.

Protective Drilling

Drilling of a well to prevent drainage of petroleum to a producing well on an adjoining lease is a common goal of both the lessor and lessee. Preventive drilling may be required in fields that contain a mixture of Federal land and patented or fee land. The terms of Federal leases require drilling a protective well on the leased tract if an “offset” well is located on adjacent non-Federal land or on Federal land leased at a lower royalty rate. An “offset” well is a well drilled at the next location in accordance with the established spacing rule to prevent (or protect) the drainage of oil and gas to an adjoining tract where a well is being drilled or is already producing.

Pool Discoveries

Discovery of a “new pay zone” within an existing field is a “pool” discovery, as distinguished from a new field discovery. A pool discovery may result in the drilling of additional wells—often on the same well pads as currently producing wells, or often sharing the same boreholes or separated only by a few feet. Currently producing wells also may be drilled deeper to the new pay zone. Each new pay zone developed requires additional flowlines, storage, and treatment facilities if the fluids from the various pools are to be kept separate. Some fields contain as many as seven or more pay zones all sharing a geologic structure that created the conditions for the accumulation of oil and gas.

PRODUCTION

Production is a combination of operations that includes (1) bringing the fluids (oil, gas, and water) to the surface; (2) maintaining and/or enhancing the productive capacity of the wells; (3) treating and separating the fluids; (4) purifying, testing, measuring, and otherwise preparing the fluids for market; (5) disposing of produced water; and (6) transporting oil and gas to market.

Production of oil and gas from a single well usually is initiated as soon as drilling and completion operations are completed and the well is developed for production. In the meantime, other wells may be in production, being drilled, or exist only in the field development plans. It may take a few months to several years before a field is fully developed. Therefore, field development activities and those activities normally associated with oil and gas production occur simultaneously during the early life of a field. Drilling of new wells is undertaken periodically throughout the life of a producing field to increase or maintain production from the reservoir.

Well Completions

After a well has been drilled and evaluated for its economic worth and profit, work to set the casing and prepare the well for completion and production begins. The decision to complete an individual well for production is based on the type of oil or gas accumulations involved, the expected future development that may be undertaken during the life of the well, and the economic circumstances at the time that the work is done. Completion equipment and the methods employed vary.

Well completion involves installation of steel casing (production casing) between the surface casing (or last drilling casing) and the oil and gas producing zone. The steel casing then is cemented to provide wellbore stability and protect specific zones (i.e., fresh water aquifers). The casing is perforated at the "pay zone," which then may be "stimulated" or "treated" to increase productivity.

The drilling rig and most of the support equipment are moved from the well site after the production string or casing is cemented. Small diameter "production" tubing is then placed inside the casing down to the producing zone. The tubing is connected to the surface equipment and transports the oil and gas from the bottom of the well to the surface. If the pressure is sufficient to raise a column of oil or gas to the surface, the well is completed as a flowing well. When pressure is not sufficient, a pumping system is installed. Typically, oil wells require a pumping unit. After the well is completed, the well can be tested for a period of days or months before another well is drilled.

Temporary storage tanks normally are used to hold the produced oil during testing. A "separator" is required to separate the gas from the oil or from produced water. Typically, a well is shut in until it is connected unless the oil well is associated with small amounts of gas uneconomical for hook up and sales. In that case, the gas separated from the oil may be burned off, or flared, as waste until a pipeline connection is available. Temporary flaring is conducted in accordance with NTL-4A, Beneficial Use, for testing purposes. If water is produced with the oil, a "treater" is needed to separate emulsified oil and water.

Well Completion Report

A "Well Completion or Recompletion Report and Log" must be filed with the BLM within 30 days after completion of a well for production. The completion report reflects the mechanical and physical condition of the well. Geologic information and, when applicable, information on the completed interval and production is required. Operators must notify the BLM no later than the fifth business day after a well begins production. The information in these reports may be withheld from the public if the operator requests that it be held as proprietary information.

Well Stimulation

"Well stimulation" is employed to enlarge channels or create new ones in the producing formation rock to enhance oil and gas production. Because oil is usually contained in the pores or fractures in a reservoir formation, enlarging or creating new channels allows the oil or gas to move more freely to a wellbore. A well may be restimulated several times during its lifetime to maintain or increase production. There is a short-term increase in activity at the well site during this process. Generally no new surface disturbance is required to perform these operations. Two basic well stimulation methods are commonly used—treatment and hydraulic fracturing.

Acid treatment dissolves rock with weak hydrochloric acid, thereby enlarging existing channels and opening new ones for oil or gas to flow to the wellbore. Reservoir rocks most commonly acidized are limestone (calcium carbonate) and dolomite, which exhibit low permeability. Well servicing rigs are used to prepare both new and old wells for acid treatment.

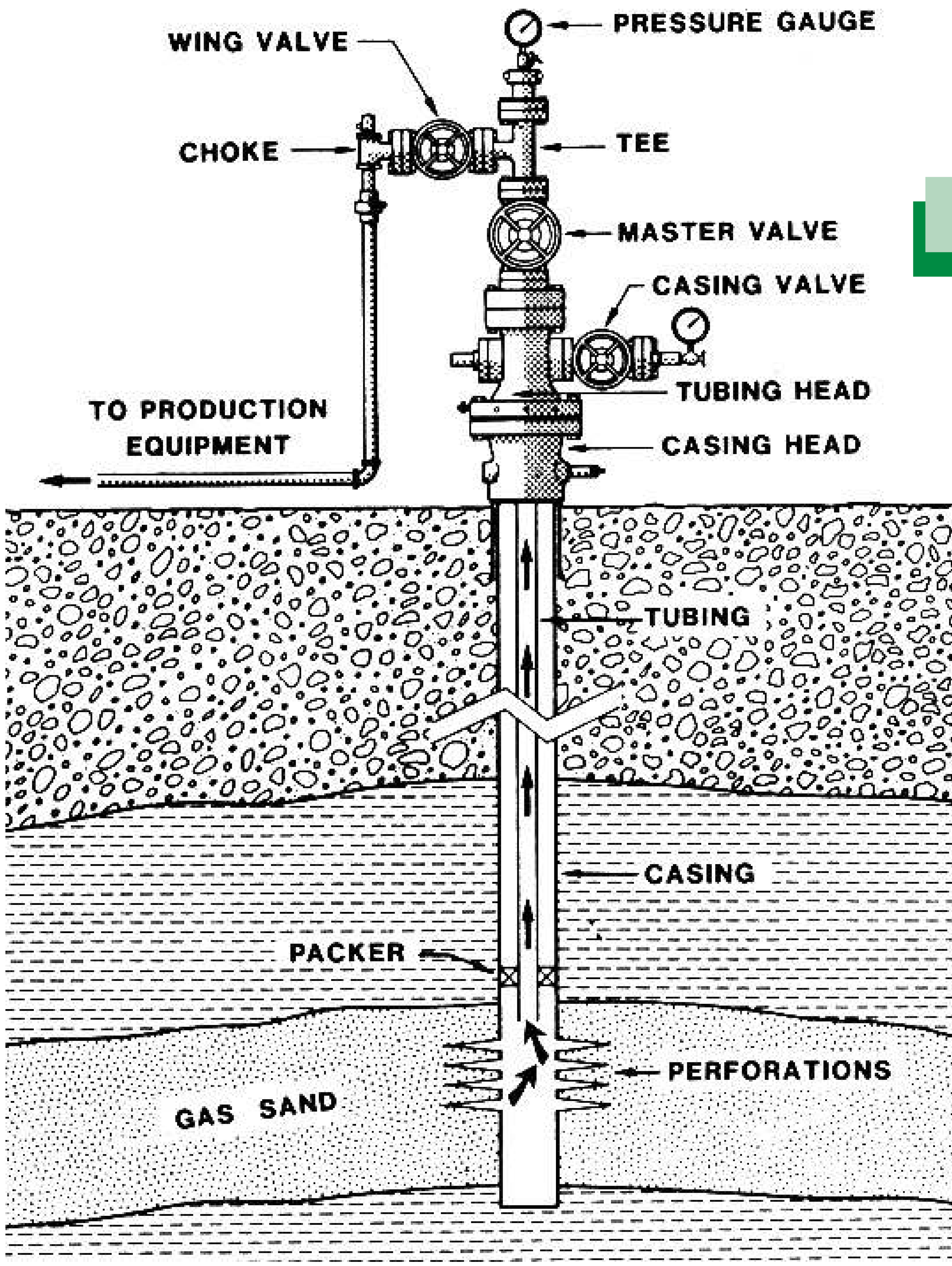
Hydraulic fracturing is used to create or enlarge cracks in sandstone reservoirs in the same manner as acid treatment is used in limestone or dolomite reservoirs. Hydraulic pressure is applied against the formation by pumping fluid, and proponts sand under high pressure, into the well. This pressure splits and cracks the rocks while keeping the fractures open to improve the productivity of the well, or increase the rate fluids that can be injected into disposal wells. Most well pads are of sufficient size to accommodate the trucks and other equipment needed to complete a "frac" job; however, a second pad and additional surface disturbance may be required for safety considerations and to accommodate the large amount of equipment needed to perform special "massive fracture" jobs.

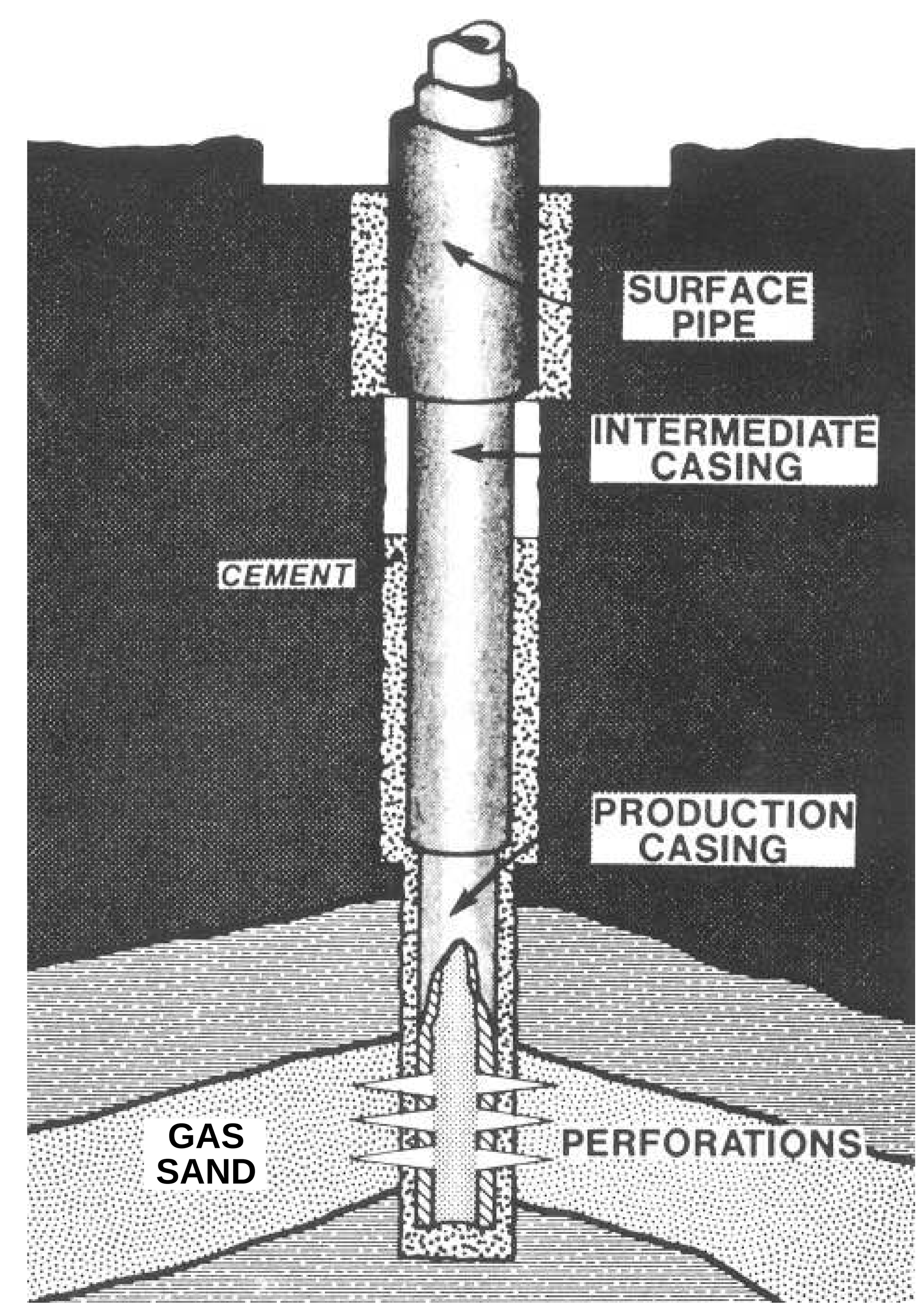
Oil Wells - Wellhead Facilities

The "wellhead" is the equipment installed to maintain control of the well at the surface and to prevent well fluids from "blowing" or "leaking" at the surface. The pressures encountered in the well determine the type of wellhead equipment needed. This varies from a simple assembly to support the weight of the production tubing in the well to a high-pressure wellhead to control reservoir pressures.

Flowing Wells

Surface equipment at the head of a flowing well is limited to a series of valves, or a "Christmas tree," and possibly a fenced area ranging from 15 feet by 15 feet (5 meters by 5 meters) to 50 feet by 50 feet (15 meters by 15 meters) around the wellhead (Figure B-4). A service area also may contain a small (1 foot by 2 feet by 3 feet) gas-powered chemical pump and "guy line" anchors for servicing units brought in for well repairs. Chemical pumps used to inject emulsion breakers, corrosion inhibitors, or paraffin solvents into the well or flowline may be present.





Casing strings
cemented in the hole

Typical Flowing Well

Figure B-4

Artificial Lifts (Pumping)

When a well is completed, the natural reservoir pressure may drive the fluid to the surface. At some time during the life of a well, the pressure is depleted and some form of artificial lift may be used to raise the fluid to the surface. The most common methods of artificial lift are sucker rod pumps, centrifugal pumps, hydraulic pumps, and gas lift. All of the pump systems require some type of surface equipment and a power system. All power systems generate noise; however, this ranges from almost none for electric motors to high noise levels for single cylinder gas engines.

Sucker Rod Pumps

The pumping unit is the most visible and recognizable piece of equipment within oil fields. Pumping units vary in size from 4 feet (1.2 meters) to more than 25 feet (7.6 meters) in height depending on depth of well. The principle of the sucker rod pump is the same as that of the common hand pump used to lift water. A series of rods and a valve move up and down through a “stuffing box” in the well to bring the oil to the surface. The stuffing box is regularly maintained to prevent oil leaks from the wellhead. Failed packing in stuffing boxes is a common cause of oil spills. The rod is connected to a reciprocating pumping unit or “pump jack.” Surface pumping units are usually powered by electric motors; however, internal combustion engines are used when electric power is not available. Single-cylinder engines operate at very high noise levels, whereas multi-cylinder engines operate at lower noise levels and electric motors at a very low noise level.

Centrifugal Pumps

Centrifugal submersible well pumps consist of a stack of 25 to 300 electric-powered small pumps located inside the well casing. Centrifugal pumps require little equipment above the ground and generate no noise at the surface. Surface equipment requirements include a switch or control cabinet, the wellhead, a spool for the cable used to transmit electricity to the pumps, and an electric power line.

Hydraulic Pumps

The pumping unit of a hydraulic system is located inside the well and is powered by oil under high pressure. The equipment required on the surface includes a storage tank for the power oil, a pump to pressurize the oil, an electric motor or internal combustion engine to power the oil pump, power oil regulating valves and pressure gauges, hydraulic pump, and the oil wells. The total surface area used for this type of facility may be greater than for other pumping systems if a centralized power system and additional oil pressure lines are used to carry the power oil from the pump to the wellheads. The noise level created at the wellhead depends on whether an electric motor or internal combustion engine is used to power the oil pump.

Gas Lift

Gas lift is commonly used where low-cost, high-pressure natural gas is available and where pressure in the petroleum reservoir is sufficient to force the petroleum part of the way up the well. In this system, natural gas under pressure is injected into the well casing. The gas forces the fluids up the production tubing to the surface. The gas pressure maintained inside the casing creates a flowing well. The surface equipment used for gas lift includes a gas compressor, oil storage tank, and separator. The system is quiet if the compressor is powered by an electric motor and little physical space is required at the wellhead.

Gas Wells

Most gas wells produce by normal flow and, in most cases, do not require pumping. Surface use at a flowing gas well usually is limited to a 20-foot by 20-foot (6-meter by 6-meter) area. Formation water may enter a gas well and choke off the gas flow. A pump then is installed to pump off the column of water. Some gas wells may require periodic to almost continual water pumping. The typical gas wellhead facilities are similar to those of a flowing oil well, consisting of a relatively unobtrusive wellhead "Christmas tree" (see Figure B-4).

Oil Field Gathering Systems

Crude oil is transferred in small diameter pipelines called "flowlines" from the wells to treatment facilities and a central tank storage battery before it is transported from the lease. The flowlines may be constructed with 3- or 4-inch-diameter steel pipes, but plastic pipe is more commonly used.

Flowlines may be placed on the surface of the ground or they may be buried. If buried, the installation of flowlines is similar to small-scale pipeline construction.

Generally, a level bed is constructed to provide for vehicle access, trenching, and burial of the flowline. Flowlines often are installed in, or adjacent to, a roadbed to reduce surface disturbance and facilitate its installation.

After the oil is gathered from the field and is treated, measured, and tested, it is transported from the lease by pipeline or trucked to market.

Gas Field Gathering Systems

Natural gas often is sold at the wellhead and transported directly off the lease. If processing and conditioning are required to remove liquid hydrocarbons, and water, the gas may be transferred to a central collection point and treating facility through flowlines prior to sale. Gas gathering systems may include equipment for conditioning and upgrading the gas and compressing the gas so that it flows through the pipelines and all systems have a controller, a measuring device, and recorder for the production flow.

Large compressors are used to compress the gas. Pressures may range from 509 to 1,000 pounds per square inch (psi). Large reciprocating compressors driven by gas engines are used, but centrifugal units driven by gas turbines or electric motors also are used. Large compressor stations along the pipeline often use natural gas from the pipeline for fuel. Storage and maintenance facilities for the gas field's operations usually are located at the compressor station. Compressor stations are the largest and most visible features in a gas field and are the center of most of the human activity.

Oil and Gas Separating, Treating, and Storage Facilities

Fluids produced from a well normally contain oil, gas, and water. The oil, gas, and water are separated or treated before the oil is stored in the tank battery. The treating facilities may be located at the wellhead, but in a fully developed field, they are usually located at a central tank battery site. If enough natural gas is produced with the oil to warrant separation, it will be separated from the fluids, compressed, and transported by pipeline directly to market.

Enough "casinghead gasoline" or "drip gas" may be produced in the field to make it economical to process it for marketing. In that case, a "gasoline" plant may be built in the area to remove natural gasoline, butane, and propane. Some of the residue gas may be used to fuel gas compressors, pump engines, and heat the separating and treating vessels. The remainder of the gas is marketed.

The oil and water produced from a well are usually in the form of an emulsion. Water is separated and removed after the gas is removed. The type of treatment facilities used depends on the amount of emulsification. If emulsification is high, chemical and/or heat treatment is used to separate the oil and water. Heat is applied in a facility called a "heater-treater," which breaks the oil in water emulsification. The heat is supplemented in most cases by chemical emulsion breakers. The oil and water, when not highly emulsified, may be separated by gravity in a tall settling tank called a "gun barrel." Conducting equipment such as separators, heaters, dehydrators, and compressors may be located at the wellhead where the oil and gas first reach the surface or at the tank batteries and/or gas compressor stations in the field.

After the oil and water are separated, the oil is piped to storage tanks (tank batteries). The tank batteries are usually located on, or in the vicinity of, the lease. Tank batteries usually contain at least two tanks. The number and size of tanks and other equipment vary with the rate of petroleum production from the field. Tank battery sites may occupy from 1 to 5 acres depending on associated facilities and number and size of tanks. Often, the well pad is used for setting the tank batteries; however, if tank batteries are located off site, new construction may be needed.

Although natural gas is produced in varying quantities with the crude oil, in many fields the primary or sole production is the natural gas itself. Field processing to upgrade the gas for transportation and marketing consists of two primary treatments. The first is to separate the natural gas from crude oil and/or other liquid condensates including free water. In this process the gas is run through “separators” and/or a “heater” to separate the liquids from the gas. The gas then is run through a “dehydration unit” to remove the remaining water vapor. The removal of the water vapor is important because in the presence of natural gas or other hydrocarbons it will form “hydrates” that precipitate out and cause blockage of pipelines. The treatment of the gas is done either at the wellhead or at a centralized field facility located at the tank battery site or at a compressor plant. No gas is stored at these facilities, but is entered directly into additional gathering or marketing pipeline after treatment.

Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are “associated gases” commonly produced with the natural gas. H_2S is extremely toxic, heavier than air, highly corrosive to unprotected metal, and will cause eventual failure of the metal. Unless these gases are present in the very small quantities, they must be removed from the natural gas. There are several processes used to remove “acid gases.” The most common is the alkanolamine process in which the gas is absorbed in an alkanolamine solution.

Disposal of Produced Water

After water is separated from oil at the tank battery, it is disposed under BLM approval and supervision. Although most produced waters are brackish to highly saline, some produced waters are fresh enough for beneficial surface use.

Produced water from oil and gas operations is disposed of by subsurface injection, into lined or unlined pits, or other methods acceptable to the BLM, in accordance with the requirements of Onshore Order No. 7. Disposal of produced water by disposal/injection wells requires permit(s) from the primacy State or U.S. Environmental Protection Agency (EPA). In New Mexico, the New Mexico Oil Conservation Division has jurisdiction over water disposal. Approval of surface use by the surface-management agency, if other than the BLM, also is required.

Advantages and disadvantages of the alternative water disposal systems vary. Surface systems (lined evaporation pits) may require an area larger than the tank batteries. Because produced water seldom issues from heater-treaters completely free from oil, oil skimmer pits are installed between the separating facilities and the evaporation pits. If a skimmer or evaporation pit is accidentally breached, oil and/or produced water spills may occur. Evaporation pits do not work efficiently at high elevations and cool temperatures.

When produced water is disposed underground, it is introduced into a subsurface horizon containing water of equal or poorer quality. Also, it may be injected into the producing zone from which it originated to stimulate oil production. Dry holes or depleted wells may be converted for produced-water disposal. Occasionally new wells will be drilled for this purpose. Well completion requirements for an underground injection well typically are more stringent due to higher pressure requirements. An injection pump is used to force the produced water into the disposal zone. Produced water is prevented from migrating up or down from the injection zone and into other formations in disposal wells.

Secondary and Enhanced Recovery of Oil

Oil, gas, and water typically are trapped within fine rock pores under high pressure in the oil reservoir. The well provides a low-pressure zone in the rock. Expansion of pressurized water and gas in solution forces oil out of the rock pores into the well and up to the surface. This is known as the “primary drive” or “primary recovery.” Oil flowing out of the rock drains pressure from the formation, pressure in the reservoir begins to slowly decline, primary drive diminishes, and the production rate falls. Oil cannot be produced unless pressures within the reservoir are maintained or restored to cause displacement of the oil being held in the rock and to drive it to the wellbore. Usually, only 15 to 20 percent of the oil is recovered from a reservoir during primary production. As reservoir pressures continue to drop, gas in the oil escapes, forming bubbles in the rock pores. Installation and implementation of a secondary and enhanced recovery system significantly increase a field’s productivity and longevity. Many reservoirs are developed for secondary and enhanced recovery early in the life of a field.

Secondary Recovery Methods

Fluid injection is a secondary recovery operation in which a depleted reservoir is restored to production by the injection of liquids or gases (from extraneous sources) into the wellbore. In essence, this injection restores reservoir pressures and moves some of the formerly unrecoverable oil through the reservoir to the well. Secondary recovery can double the total amount of oil produced from a field. Fluids are forced into selected injection wells to force the oil to production or recovery wells nearby. Two of the more common fluid injection methods are waterflood and produced water disposal.

The installation of a secondary recovery system involves drilling of injection wells and new recovery wells or conversion of production wells to injection wells. Fluid injection lines are installed and additional water separation and storage facilities are constructed to implement the secondary recovery system. Secondary recovery results in a significant increase in the amount of water produced. Additional land area is needed to accommodate water supply facilities, water storage and treating facilities, water injection pumps, and waterlines to wells. Drilling and construction and other human activities intensify in the oil field during installation of a fluid injection system. Water can be appropriated from fresh water sources or be produced water from the formation.

Waterflood

The most commonly employed form of secondary recovery is waterflooding. Water is injected into the reservoir under pressure to drive additional oil to the producing wells. On the average, a successful waterflood doubles the amount of oil recovered from a reservoir. In some fields, water for waterfloods is injected into depleted existing wells. In other cases, additional wells may need to be drilled for water injection. Most waterfloods are difficult to operate on a lease basis, so entire fields, if not already being operated under a unitization agreement, usually are unitized before flooding. If unitization precedes a waterflood, there is little or no duplication of secondary recovery facilities. However, additional surface area is used for the water supply facilities, water storage and treating facilities, water injection pumps, and waterlines to injection wells. If the injection well is a converted producing well, the waterline replaces the producing flowline. If the injection well is a converted dry hole or a new well drilled for the waterflood, the water injection line is the only addition to the pipeline system and requires the same amount of land as a flowline for a producing well. Usually, after a waterflood project is established, additional new water is not needed. The produced water is reinjected.

Although not a secondary recovery process, produced water disposal is a common form of fluid injection. Its primary purpose is simply to dispose of the produced water produced with crude oil. A typical system is composed of collection centers in which produced water from several wells is gathered, a central treating plant in which corrosion-forming substances are removed, and a disposal well. The produced water is injected into the originating zone and used to pressurize and drive the oil towards the borehole of a producing well.

Gas Injection

Gas injection is a secondary recovery technique that is generally used only in oil and gas reservoirs that have an existing gas cap. Natural gas is injected under pressure to restore and maintain reservoir pressures to displace and move oil to the producing wells.

Enhanced Recovery Methods (Tertiary Recovery)

Enhanced recovery methods increase the amount of oil produced and recovered from an oil reservoir beyond that obtained from primary and secondary methods. Enhanced oil recovery techniques employ chemicals, water, gases, and heat either singly or in combination, to reduce the factors that inhibit oil recovery. Considerable technical and financial risk is involved because of the large investment in equipment and the unknown factors or characteristics of the oil reservoir that may affect the success of an enhanced recovery method. There are three broad categories of enhanced recovery methods currently used, namely (1) thermal enhancement, which primarily involves injecting high-pressure steam into the oil reservoir to reduce oil viscosity and increase its ability to flow; (2) miscible flood, in which propane, butane, natural gas, CO_2, or other gases are injected into the reservoir to dissolve and displace the oil; and (3) chemical enhancement, which includes injecting polymers to thicken injected waters to increase uniformity of oil displacement in the reservoir or injecting detergents ("surfactants") that essentially "wash" the oil from the reservoir rocks.

As with secondary recovery systems, additional land surface is required to accommodate the injection and oil recovery systems. This includes additional wells, injection lines and flowlines, roads, storage and treatment facilities, pumps, and injection equipment.

Transportation Pipelines

A transportation pipeline is commonly used to transport natural gas and oil to market or refineries. In most cases, oil is transported to the refinery via pipeline, although trucks may be used to transport oil from isolated fields or new fields to pipeline terminals or the refinery.

The oil and/or gas is moved through the pipeline by pumps. Pump stations are located either at gathering stations or trunkline stations or a combination of both. A gathering station can be located in or near a field and receives the product through a pipeline gathering system or from tank trucks from the operators' tanks. From the gathering station, product is relayed to a trunkline station, which is located on the main pipeline, or trunkline. The trunkline station relays the product for processing or shipping terminals. To maintain pressure, booster pumps are spaced along the trunkline. Tank batteries located along the line can receive and temporarily store the product before it continues.

Months and sometimes years of engineering studies and surveys of potential gas reservoirs and markets precede the final decision to build a pipeline.

Construction of a large transportation pipeline may involve as many as 250 to 300 workers in a normal operation and up to 500 workers in a very large operation. The amount of construction equipment needed depends on the variety and difficulty of terrain. Stream crossings, marshes, heavily timbered forests, steep slopes, or rocky ground can require different types of equipment and construction practices. Crews of 250 to 300 workers can move at a rate of 3 miles a day with a distance of sometimes 10 or 15 miles separating the beginning of the work crew from the end.

In practice, a strip of land from 50 to 75 feet (15 to 23 meters) wide is cleared depending on the size of the pipe and type of terrain. The clearing crews open fences and build gates, cattle guards, and bridges. Salable timber cut by clearing crews is stacked; the rest is cut and disposed. A roadway capable of supporting vehicle access is graded and completed adjacent to the pipeline. The cleared area needs to be wide enough for the pipeline trench, the largest side-boom tractor, and transportation of pipe and equipment. In rocky terrain, a machine equipped with a ripper that extends several feet into the ground often is used to loosen rocks for removal before the ditching operation begins.

A ditch is made by loose-dirt ditching machines or by wagon drills suspended from side-boom tractors. Dynamite blasting is used for very hard rock surfaces. Pipe is transported to the ditching sites where the pipe is coated, double jointed, welded, and lowered into the ditch. The pipe must be buried deep enough to ensure that it does not interfere with normal surface uses. The U.S. Department of Transportation requires a minimum of 36 inches (approximately 1 meter) of cover. The trench is backfilled and compacted; the cleared area is contoured, waterbarred, and revegetated; and the pipeline route is marked.

Well Servicing and Oil and Gas Field Maintenance

Producing wells in active oil and gas fields periodically require repair and workover operations. Operations involving no new surface disturbance to redrill, deepen, and plug-back require prior approval of the authorized officer of the BLM. No prior approval or subsequent report is required for well clean-out work, routine well maintenance, bottom hole pressure survey, or for repair, replacement, or modification of surface production equipment provided no additional surface disturbance is involved.

When prior approval is required, the operator must submit a Sundry Notice or APD as applicable. A detailed written statement of the plan of work must be provided to the authorized officer with the appropriate form. When additional surface disturbance will occur, a description of any subsequent new construction, reconstruction, or alteration of existing facilities, including roads, damsites, flowlines and pipelines, tank batteries, or other production facilities on any lease, must be submitted to the authorized officer for environmental reviews and approvals. Emergency repairs may be conducted without prior approval provided the authorized officer is notified promptly.

Servicing of individual wells to improve or maintain oil and gas production is an activity that extends throughout the life of the field. This work usually is performed with the use of a well- servicing unit or self-propelled workover rig, which is similar to a scaled-down drilling rig although they are commonly truck-mounted. Both the workover rig and well-servicing unit carry hoisting machinery that is used to pull sucker rods and tubing from the wellbore. The most common well-servicing operations include cleaning out the well, changing pumps, repairing rod string and tubing, changing the producing and re-establishing oil-producing intervals, installing artificial lift, and repairing casing and other downhole equipment. There is an intense, but short-term, increase in human and motorized activity at the well site during servicing.

Construction, reconstruction, and normal maintenance work continue throughout the life of the field. Flowlines, pipelines, pumping units and other oil and gas field equipment, no longer functional because of corrosion, metal fatigue, wear, or because it has become outdated and inefficient, is replaced, upgraded, or abandoned and removed. Major and minor maintenance activities are a normal part of the operations during the life of the oil and gas field.

Pollution Control

All spills or leakages of oil, gas, produced water, toxic liquids or waste materials, blowouts, fires, personal injuries, and fatalities must be reported by the operator to the BLM and the surface-management agency, if other than the BLM. The BLM requires immediate reporting of all major undesirable events (more than 100 barrels of fluid/500 thousand cubic feet of gas released or fatalities involved). A spill prevention, control, and countermeasure (SPCC) plan is required only for wells that have the potential to discharge into waters of the United States.

Firewalls/containment dikes must be constructed and maintained around all storage facilities/batteries. The containment structure must have sufficient volume to contain, at a minimum, the entire content of the largest tank within the facility/battery, unless more stringent site-specific protective requirements are deemed necessary by the authorized officer.

Inspection and Enforcement

The BLM has developed procedures to ensure regular inspections (at lease once a year) on leaseholds that are producing or expected to produce significant quantities of oil or gas in any year, or have a history of noncompliance. Other factors such as health, safety, environmental concerns, and potential conflict with other resources also determine inspection priority. Inspections of leasehold operations ensure compliance with applicable laws, regulations, lease terms, Onshore Oil and Gas Orders, notices to lessees, other written orders of the authorized officer, and the approved plans of operation.

ABANDONMENT

All abandonments, whether they involve one wildcat well, a well no longer productive, or an entire leasehold, require the approval and acceptance of the abandonment of the individual well(s) by the

BLM. An acceptable abandonment includes plugging the wellbore and reclaiming the land surface to a stable and productive use.

Approval of Abandonment

Well abandonment operations may not commence without prior approval of a "Sundry Notices and Reports on Wells" by the authorized officer of the BLM. The Sundry Notice serves as the operator's Notice of Intent to Abandon (NIA). In the case of newly drilled dry holes, failures, and in emergency situations, oral approval may be obtained from the authorized officer followed by written confirmation. In such cases, the surface reclamation requirements will have been discussed with the operator and stipulated in the approved APD. For older existing wells that do not have an approved SUPO, a reclamation plan must be submitted with the NIA. Reclamation requirements are part of the approval of the NIA. The operator must contact the BLM prior to plugging a well to allow for approval and witnessing of the plugging operations.

Plugging of Wells

The purpose of plugging a well is to prevent fluid migration between zones within the wellbore, protect aquifers of useable quality water, protect other minerals from damage, and assist in the reclamation of the surface area. Well plugging requirements vary with the characteristics of the rock, geologic strata, well design, and reclamation requirements. For wells no longer capable of production, all perforations must be isolated so as not to allow fluid to migrate up hole or the surface or to allow migration downward. The perforations may be isolated by (1) placing a cement plug across the perforations and that extends 50 feet (15 meters) above and below the perforations, or (2) setting a cement retainer (cement tool that acts like a plug except that cement can be pumped below the tool but no fluid can pass above the tool) plus or minus 100 feet (30 meters) above the perforations and pumping a sufficient volume of cement into the perforations, or (3) setting a bridge plug (a tool similar to a cement retainer except that no fluid can pass in either direction) plus or minus 100 feet (30 meters) above the perforations and placing 50 feet (15 meters) of cement on top of the bridge plug. The production casing may be removed. If the casing is cut and removed, the casing stub (the top of the casing remaining in the hole) must be plugged with a 100-foot cement plug to extent 50 feet (15 meters) inside the casing stub and 50 feet (15 meters) outside the casing stub (open hole). If casing is not removed, the surface casing shoe must be isolated by perforating the production casing near the surface casing shoe. A cement retainer must be set plus or minus 100 feet (30 meters) above the perforations and a sufficient volume of cement pumped below the retainer, through the perforations, and between the outside of the production casing and the inside of the surface casing for a distance of 100 feet (30 meters). All cement plugs must have sufficient volume to fill 100 feet (30 meters) of hole plus an additional volume of 10 percent per 1,000 feet of depth (a 100-foot plug at 5,000 feet would be required to have an additional 50 feet [15 meters] of cement). At the surface, all annular spaces must be plugged with at least 50 feet (15 meters) of cement.

The operator's plan for plugging and abandonment is submitted with the NIA and is reviewed for completeness and adequacy. Although the plugging of each well must be designed individually, the minimum requirements are described below.

In open hole situations, cement plugs must extend at least 50 feet (15 meters) above and below zones with fluid that has the potential to migrate, zones of lost circulation (this type of zone may require an alternate method to isolate), and zones of potentially valuable minerals. Thick zones may be isolated using 100-foot plugs across the top and bottom of the zone. In the absence of productive zones and minerals, long sections of open hole may be plugged by placing plugs every 3,000 feet. In cased holes, cement plugs must be placed opposite perforations and extend 50 feet (15 meters) above and below except where limited by plug back depth (see Onshore Oil and Gas Order No. 2).

A permanent abandonment marker is required on all wells unless waived. This marker pipe is usually 4 feet above the ground and embedded in cement at the borehole site. The pipe is capped and the well's identity and location permanently inscribed.

Dry wildcat and development wells normally are plugged before the drill rig is removed from the well site. This allows the drill rig to plug the hole and avoid the necessity of bringing in other plugging equipment.

Before a lessee/operator abandons a well no longer capable of production, it must be shown that it is no longer suitable for profitable operation. Wells are normally plugged when they are no longer capable of production. However, if a well has potential for use in a secondary recovery program, it may be allowed to stand idle. Truck-mounted equipment is used to plug former producing wells.

Surface Reclamation

A reclamation plan is a part of the SUPO. Reclamation may be required of any surface previously disturbed that is not necessary for the continued well or other operations. When abandoning a well and other facilities that do not have a previously approved reclamation plan, a plan must be submitted with an NIA. Additional reclamation measures may be required based on the conditions existing at the time of abandonment. Any additional reclamation requirements are made part of the conditions of approval of the NIA. The general standards and guidelines for reclamation and abandonment of oil and gas operations are set forth in the Surface Operating Standards for Oil and Gas Exploration and Development "Gold Book." Additional standards and requirements may be applied to accommodate the site-specific and geographic conditions of the reclamation site (see Appendix A-III).

Inspection and Final Abandonment Approval

Final abandonment is not approved until the surface reclamation work required by the APD or NIA is completed and the required reclamation is acceptable to the BLM or appropriate surface-management agency or private surface owner. The operator must file a Subsequent Report of Abandonment following the plugging of a well. A Final Abandonment Notice, which indicates that the site is ready for inspections, must be filed upon completion of reclamation.

Release of Bonds

A lease bond is terminated only if the well to be abandoned is the last or only well on the lease, and there are no other outstanding liabilities (e.g., unpaid royalties, rents, penalties, etc.).

APPENDIX B-II
STANDARD OPERATING PROCEDURES FOR EXPLORATION, DEVELOPMENT, PRODUCTION, AND ABANDONMENT—GEOTHERMAL

Geothermal energy is heat (thermal) derived from the earth (geo). In New Mexico, geothermal energy is defined as a mineral. Thus, a geothermal developer must hold geothermal mineral rights for property on which geothermal resources are being produced. Additionally, if that geothermal energy is conveyed to the surface via groundwater, the developer also must have or acquire the appropriate water rights for the use of the groundwater. Because the heat is considered the mineral, the right to use or consume the groundwater is not conveyed with the lease in declared underground water basins. The State Engineer of New Mexico certifies and licences the rights to beneficially use water in the declared underground water basins of New Mexico.

Once a lease for the mineral rights and the certificate and license to appropriate groundwater are issued, the lessee or developer may enter the leasehold to conduct operations unless otherwise limited by special stipulations. Similar to oil and gas exploration, geothermal exploration can include many activities for which the lease or water right does not have to be obtained. However, just as in the oil and gas industry, if a lease position and water rights cannot be acquired, exploration expenditures probably will not occur. An exploration permit is required for any exploration operations as defined in 43 CFR 3200.1.

The following discussion depicts what can be expected to occur, and is assumed will occur for the purposes of this analysis, when geothermal resources are discovered and development of a lease is undertaken. It also is assumed that the technology of geothermal exploration and development will not change significantly during the life of this document. This section is an integral part of the assumptions made in Chapters 2 and 4 of this document.

Successful exploration and development generally progresses through four basic operational phases. These include (1) preliminary exploratory investigation, (2) test drilling, (3) development/production, and (4) abandonment, which are described below.

PRELIMINARY EXPLORATORY INVESTIGATIONS

Preliminary exploratory investigations can be conducted from either the air or the surface. A lease is not required to conduct these investigations for Federal geothermal resources; however, some surface exploration methods such as seismic or shallow temperature surveys must be reviewed and approved by the surface-management agency. Any of these investigations also can be conducted after lease acquisition.

Airborne exploration can include gravity surveys, magnetotelluric surveys, seasat radar images, and other remote sensing techniques. Surface exploration methods include geologic mapping, heat flow and thermal conductivity surveys, resistivity and self-potential surveys, trace element geochemical and soil surveys, and seismic surveys. Most of these investigations involve only casual use (e.g., with little or no disturbance to the surface or resources) and no permits are required. Generally, the surveys are conducted using existing roads and trails. However, investigators must comply with the rules and regulations of the appropriate surface-management agency. The geothermal lease does not grant an exclusive right to conduct exploratory investigations. Exploratory activities may be conducted prior to or after leasing lessee by or someone other than the lessee. These investigations may result in an expression of interest to lease specific areas.

An exploration permit is required for any exploration operation except under the following conditions as defined in 3250.10 (b): on unleased land administered by a Federal agency other than the Bureau of Land Management (BLM), for unleased geothermal resources underlying surface land that is managed by another Federal agency, on privately owned land, or involving casual use activities (as defined in 3200.1 as activities that ordinarily lead to no significant disturbance of Federal land, resources, or improvements). Exploration operations are defined in part as any activity relating to the search for evidence of geothermal resources where the explorer is physically present on the land and the activities may cause damage to those lands. Exploration operations do not include the direct testing of geothermal resources or the production or utilization of geothermal resources. A developer must comply with 43 CFR Subparts 3250 through 3256. To acquire a exploration permit, the developer must follow the information required in 43 CFR 3251.

Many of the exploration methods used for geothermal exploration also are used for oil and gas exploration and have been described in Appendix B-I. The temperature survey, however, is more specific to geothermal exploration.

A temperature gradient survey, or heat flow survey, is conducted by drilling up to 30 small-diameter wells. Typically these wells are drilled at a density of one well per township. The wells can be drilled with mud, foam, or air rotary to depths between 250 to 450 feet (76 to 137 meters) deep. The wells are typically completed by placing polyvinyl chloride (PVC) casing into the wellbore and filling the casing with water. Typically one well a day can be drilled and set. Once all wells are completed, the temperature gradients in the wells are measured. Upon completion of the survey, the casing is removed and the well abandoned in accordance with State Engineer’s Office regulations and the exploration permit requirements. Additionally, well pads and roads are abandoned and reclaimed in accordance with the exploration permit requirements. All reports and notices must comply with 43 CFR 3253 and applicable portions of 43 CFR 3250 through 3256.

TEST DRILLING

If the preliminary exploration program indicates high potential for geothermal resources in a specific area, test drilling may be conducted. Because geothermal energy must be used at the well location, not only must the geothermal potential be present, but its end use must be identified in order to justify drilling the test well. Test wells provide subsurface data, locate potential productive zones, delineate the reservoir limits, and aid in determining the properties of the reservoir and reservoir fluids. These test wells are very similar to oil and gas exploratory drilling with the exception that a geothermal test well is much shallower—1,000 feet (305 meters) at the deepest and typically 100 to 500 feet (30 to 152 meters).

While the test well is drilled for the purposes of "testing" the geothermal prospect, its location usually is selected with production in mind as well. Because of the high temperature and corrosive nature of geothermal fluids and the hard rocks found in geothermal environments, geothermal drilling is difficult and expensive. Each well can cost up to $1 to 4 million. Drilling costs account for one-third to one-half of the cost of a geothermal project (Utah Energy & Geoscience Institute, University of Utah, website www.egi.utah.edu, 1999).

Test well drilling is authorized by a Federal oil and gas lease, but cannot be conducted unless an operations plan and a drilling program are approved. Operations must be in compliance with all of 43 CFR Subpart 3260 et al. to drill and test geothermal resources. Additionally, the developer must appropriate the groundwater in the declared underground water basins by submitting an Application to Appropriate to the State Engineer.

Proposed construction and other operations that involve surface disturbance conducted under the terms of a lease must be approved by the appropriate surface-management agency before such activities are mitigated. Regardless of the surface-management agency with jurisdiction over the proposed site, the proposed drilling, development, and production operations also must be approved by the BLM.

An application for permit to drill (APD) must include (1) an operation plan (surface use program) and (2) a drilling program. The detailed information that is required to be submitted under each plan/program is identified in 43 CFR 3261.12 and 3261.13, respectively. An onsite inspection of the proposed well site, road location, and other areas of proposed surface use is conducted prior to approval. The inspection team includes BLM representatives, the lessee or developer, principal drilling and construction contractors, and other relevant parties. The purpose of the onsite inspection is to identify problems and potential environmental impacts associated with the proposal and the methods for mitigating those impacts. These may include making adjustments to the proposed well site and road locations, identifying the construction methods to be employed, and identifying reclamation standards for the lands after drilling.

The surface-management agency is responsible for preparing the environmental documentation to satisfy requirements of the National Environmental Policy Act and associated regulations, and may provide mitigation measures as needed to protect surface resource values for APD approvals. The BLM is responsible for approval of the drilling program, protection of groundwater resources, and final approval of the APD. When final approval is given by BLM, the developer may commence construction and drilling operations.

Other proposals to occupy the surface that involve surface disturbance, but are not associated with drilling a well, also must receive advance approval under the procedures described above.

Application to Appropriate

If the test well is to be drilled within the boundaries of a declared underground water basin, an application to appropriate must be filed with the State Engineer in accordance with the "Rules and Regulations governing drilling of wells and appropriation and use of ground water in New Mexico." The application must state the annual amount of water to be appropriated and its intended use, as well as well location and construction and driller information. The application is reviewed to ensure the water is available, the appropriation will not impair existing water rights or impact public welfare, and/or meets water conservation requirements. Upon receipt of an acceptable application, the State Engineer publishes, at the applicant's expense, a public notice in a newspaper of general circulation in the county in which the well is located at least once a week for three weeks. Protests can be filed with the State Engineer's office up to 10 days after the date of the last publication of the notice. All valid protests will be heard by the State Engineer's Office and the application will be approved or denied. The applicant can appeal the denial. Applications may be approved with conditions.

As soon as practicable after completing the well and the application of water to the intended use pursuant to the permit, the developer must prepare and file a Final Inspection and Report to the State Engineer's Office in accordance with the Rules and Regulations. Upon receipt of the Final Inspection and Report together with the required attachments, the State Engineer will issue to the developer a Certificate and License to Appropriate.

Surface Requirements and Construction

The well site is selected on the basis of prior surface investigations, prospect location, end use requirements, topography, accessibility, requirements of lease stipulations, and protection of surface resources.

Rights-of-way are required for all facilities, power lines, and access roads that occupy Federal land outside the lease. When a third party (someone other than the lessee/developer or the Federal government) constructs a facility or installation on or off the lease, a right-of-way also is required. The right-of-way is issued by the surface-management agency. Upon approval of the APD, the construction equipment may enter the leasehold. The types of construction equipment used include dozers (track-mounted and rubber-tired), scrapers, and motor-graders.

In general, the surface requirements and construction of a geothermal well site is similar to an oil and gas well site with the exception that the site may be smaller given the depth of the geothermal well relative to its oil and gas cousin. However, it is not uncommon for geothermal wells to have multiple-well sites as spacing requirements are very different than that for oil and gas resource development.

Drilling Operations

Drilling activities usually begin within a week after the well site and access road have been constructed. Although geothermal well depth is much shallower than an oil and gas well, most of the operation is very similar but scaled appropriately for the depth of the well.

A series of blowout preventer valves are attached to the well. The valves close down the well in the event the drill bit penetrates rock formations exhibiting extreme pressure zones that could cause unexpected changes in pressure and a well blowout. Special attention is given to the prevention of well blowouts and most of the equipment used to support the actual drilling operations is for controlling excess pressure that may be encountered. Blowout prevention equipment is tested and inspected by both the rig personnel and BLM. The drill rig crew must be trained in safety and blowout prevention.

All drilling activities and well completion operations would be conducted in accordance with the drilling program and operations plan. The well would include strings of steel pipe (i.e., casing) to line the well and prevent percolation of drilling mud or geothermal fluids into any geologic formation or freshwater aquifers above the geothermal reservoir zone. Production wells would have perforated casing or open hole completions in the geothermal reservoir zone to allow geothermal fluids to enter the well. The geothermal injection well, if installed, would be drilled and completed with multiple telescoping strings of steel casing, each cemented in place. Shallow groundwater that could be encountered during well drilling operations would be protected from commingling with deeper geothermal fluids through implementation of an approved casing and cementing program. All drilling and casing programs must be approved by the BLM as part of the APD's drilling program. Downhole production equipment (such as pumps) would be used to bring the geothermal waters to the surface.

The sumps (equivalent to the reserve pit in the oil and gas well) are typically reclaimed after drilling. Any portion of the well pad that is not used during production also is reclaimed. If the well is determined to be inadequate for the need, the well is abandoned and the well site reclaimed in accordance with 43 CFR Subpart 3263. All reports on the drilling operations must comply with 43 CFR Subpart 3264 and conditions of the APD approval.

DEVELOPMENT/PRODUCTION

Production well pads may be single-well or multiple-well pads depending on the resource availability and needs. Each wellhead temperature and pressure is monitored during operation. The facility plan is approved by the BLM and must comply with 43 CFR 3270 through 3279. The facility must be designed to operate safely and protect the environment.

Given the low temperature of the potential geothermal resources in the Planning Area, the potential end uses may include but are not limited to space heating of greenhouses, direct water use or pool heating for aquiculture, and drying in dairy production. Associated impacts depend on the traffic and size of the facility. Greenhouses and aquiculture could range in size of 1 to 30 acres. In general greenhouses employ 8 to 10 persons per acre.

ABANDONMENT

If a well or facility is determined to be no longer adequate for the need, the well is abandoned and the well site reclaimed in accordance with 43 CFR Subpart 3263. All other applicable requirements of 43 CFR 3200 et al. regarding reclamation and reporting also must be met.